STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

February 13, 2004

Agenda ID #3269
(Alternate to Agenda ID #3268)
Ratesetting

**TO:** PARTIES OF RECORD IN APPLICATION 02-05-004 AND INVESTIGATION 02-06-002

**RE:** NOTICE OF AVAILABILITY OF PROPOSED DECISION ON OPINION ON BASE RATE REVENUE REQUIREMENT AND OTHER PHASE 1 ISSUES WITH THE ALTERNATE PROPOSED DECISION OF COMMISSIONER WOOD

Consistent with Rule 2.3(b) of the Commission's Rules of Practice and Procedure, I am issuing this Notice of Availability of the above-referenced proposed decision and alternate proposed decision. The proposed decision was issued by Administrative Law Judge (ALJ) Wetzell and the alternate proposed decision by Commissioner Wood on February 13, 2004. An Internet link to this document was sent via e-mail to all the parties on the service list who provided an e-mail address to the Commission. An electronic copy of this document can be viewed and downloaded at the Commission's Website (www.cpuc.ca.gov). A hard copy of this document can be obtained by contacting the Commission's Central Files Office [(415) 703-2045].

This is the proposed decision of ALJ Wetzell, previously designated as the principal hearing officer in this proceeding and the alternate proposed decision of Commissioner Wood. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Pursuant to Resolution ALJ-180, a Ratesetting Deliberative Meeting to consider this matter may be held upon the request of any Commissioner. If that occurs, the Commission will prepare and mail an agenda for the Ratesetting Deliberative Meeting 10 days before hand, and will advise the parties of this fact, and of the related ex parte communications prohibition period.

When the Commission acts on the proposed decision or alternate proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the draft decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 25 pages.

Consistent with the service procedures in this proceeding, parties should send comments in electronic form to those appearances and the state service list that provided an electronic mail address to the Commission, including ALJ Mark Wetzell at msw@cpuc.ca.gov. and Commissioner Carl Wood at cxw@cpuc.ca.gov. Service by U.S. mail is optional, except that hard copies should be served separately on ALJ Wetzell and Commissioner Wood, and for that purpose I suggest hand delivery, overnight mail or other expeditious methods of service. In addition, if there is no electronic address available, the electronic mail is returned to the sender, or the recipient informs the sender of an inability to open the document, the sender shall immediately arrange for alternate service (regular U.S. mail shall be the default, unless another means – such as overnight delivery is mutually agreed upon). The current service list for this proceeding is available on the Commission's Web page, www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN by PSW
Angela K. Minkin, Chief
Administrative Law Judge

ANG:sid/mnt

Attachment

Decision **ALTERNATE PROPOSED DECISION OF COMMISSIONER WOOD**
**(Mailed 2/13/2004)**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Application of Southern California Edison Company (U 338-E) For Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2003, And to Reflect That Increase in Rates. | Application 02-05-004 (Filed May 3, 2002) |
| Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Southern California Edison Company. | Investigation 02-06-002 (Filed June 6, 2002) |

(See Appendix A for a list of appearances.)

**OPINION ON BASE RATE REVENUE REQUIREMENT AND OTHER PHASE 1 ISSUES**

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# OPINION ON BASE RATE REVENUE REQUIREMENT AND OTHER PHASE 1 ISSUES

## 1. Introduction

### 1.1. Summary of Decision

Returning Southern California Edison Company (SCE) to conventional cost-of-service ratemaking after a six-year hiatus, we set the company's authorized base rate revenue requirement at $2.756 billion for the 2003 test year. On an annualized basis, this represents an increase of $15 million (0.5%) above SCE's present base rate revenue of $2.741 billion for 2003. SCE had requested an increase of $251 million (9.2%). The test year revenue requirement authorized herein will be implemented in accordance with Decision (D.) 03-05-076 and related determinations made in this decision.

SCE's base rate revenue requirement covers the costs of operating, maintaining and investing in the utility's generation, distribution, and central office functions. It excludes such costs as fuel, power procurement, and public purpose programs. In D.03-07-029 we provided for the reduction of SCE's retail rates by $1.249 billion annually upon the utility's recovery of the balance of its Procurement Related Obligations Account (PROACT). This reduction was calculated using an estimate of the total bundled service ratepayer revenue responsibility of $8.472 billion, which includes the share of the Department of Water Resources revenue requirement paid by SCE's customers. Thus, the base rate revenue requirement that we authorize today, while substantial, represents approximately one-third of the consolidated revenue requirement being paid by SCE's bundled service customers. The adopted test year base revenue requirement increases the bundled revenue requirement by 0.2%.

Pursuant to the Commission's order in D.03-07-029, SCE's electric rates will be increased on a system average percentage change (SAPC) basis to give effect to the base rate revenue requirement increase adopted today. In Phase 2 of this proceeding, the Commission is evaluating proposals regarding the allocation of revenue requirement responsibility to customer classes and the design of rate structures.

We approve SCE's request to establish a late payment charge for residential customers along with an exemption for customers enrolled in the California Alternate Rates for Energy (CARE) program. We also approve in part SCE's request to adjust its charges for returned checks, reconnects, service establishment, and field assignment. We do so to more closely align rates and charges with the principle of cost causation.

We adopt, with revisions, SCE's proposed "post test-year ratemaking" (PTYR) mechanism to adjust the authorized revenue requirements for 2004 and 2005. The PTYR mechanism ties capital forecasts to actual projects in SCE's budget subject to the true-up. In connection with the PTYR mechanism, we approve a refueling and maintenance outage expense recovery mechanism for San Onofre Nuclear Generating Station Units 2 & 3 (SONGS 2 & 3).

This decision reviews certain 1997-98 generation capital additions, consideration of which was transferred from Application (A.) 99-04-024 to this proceeding. SCE is authorized to recover costs associated with $30.937 million in capital additions found to be reasonable.

Proposals by SCE and other parties to establish a system of safety, reliability, and customer satisfaction performance incentives are denied. Even though similar performance incentives have been used in connection with SCE's performance-based ratemaking (PBR) mechanism, they have not been justified in connection with conventional cost of service ratemaking.

Finally, in this decision, we examine certain of the roles fulfilled by SCE on behalf of its customers and other stakeholders. We review and comment on SCE's role with respect to integrated resource planning and whether it should be prepared to build or buy utility-owned generation capacity to serve its customers. We also review SCE's Women, Minority, and Disabled Veterans Business Enterprise (WMDVBE) program and the diversity of its workforce.

With this decision, Phase 1 of this general rate case (GRC) proceeding is concluded. Phase 2 of this proceeding addresses SCE's pricing proposals and will be resolved by future order of the Commission. This proceeding therefore shall remain open.

### 1.2. Background

In SCE's last GRC, D.96-01-011 established SCE's authorized revenue requirement for the 1995 test year. Pursuant to D.96-09-092, SCE has operated under a PBR mechanism since January 1, 1997. Pursuant to D.01-06-038 and D.02-04-055, the PBR mechanism remains in effect, with modifications, until it is superseded by the issuance of a decision in SCE's next GRC, i.e., the instant proceeding.

On May 3, 2002, SCE filed A.02-05-004 seeking, among other things, an increase in its authorized test year 2003 base rate revenue requirement. SCE originally sought authorization for revenues of approximately $3.065 billion for 2003, which represented an increase of $286 million (10.3%) above the currently authorized base rate revenue as then calculated. During the course of the proceeding, SCE revised both its request and its calculation of present revenue. Based upon its latest calculations, SCE now seeks authorization for base revenue of approximately $2.992 billion for 2003. This represents an increase of $251 million (9.2%) above the base rate revenue, now calculated at $2.741 billion. SCE also seeks authority to establish a post test-year ratemaking mechanism that would set the authorized base revenue requirements for 2004 and 2005. In addition, SCE seeks authority to establish a late payment charge for residential customers, and to increase various fees such as charges for returned checks, service establishment, and reconnection.

The Commission instituted Investigation (I.) 02-06-002 on June 6, 2002, to allow the Commission to hear proposals other than SCE's, and to enable the Commission to enter orders on matters for which the utility may not be the proponent. The Commission ordered that A.02-05-004 and I.02-06-002 be heard on a consolidated evidentiary record.

Prehearing conferences were convened on June 13 and November 1, 2002. Public participation hearings were held at 14 locations throughout SCE's service territory in October 2002. Direct and rebuttal evidentiary hearings were held before Administrative Law Judge (ALJ) Wetzell on 38 days from November 2002 to March 2003. Briefs were filed on April 18, 2003 and reply briefs were filed on May 28, 2003.[1] SCE and San Diego Gas & Electric Company (SDG&E) served update testimony on May 9, 2003. Phase 1 was submitted for decision on October 23, 2003. Final oral argument before the Commission was held following the issuance of the ALJ's proposed decision.

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[1] The procedural schedule had provided for the filing of reply briefs on May 5, 2003. (*Administrative Law Judge's Ruling on Post Hearing Procedures*, March 11, 2003, pp. 2-3.) By a ruling issued on April 30, 2003, the ALJ struck SCE's brief, directed SCE to refile its brief subject to a page limit, and set May 28, 2003, as the filing date for reply briefs.

In addition to SCE, the active parties in Phase 1 of this proceeding were the Office of Ratepayer Advocates (ORA), Aglet Consumer Alliance (Aglet), The Utility Reform Network (TURN), SDG&E, the Coalition of California Utility Employees (CUE), The Greenlining Institute (Greenlining),[2] the California Disabled Veterans Business Enterprise Alliance (DVBEA), the Natural Resources Defense Council (NRDC), and the County of Los Angeles (LA County). The positions taken by the parties are described throughout this opinion.

ORA, Aglet, and TURN have taken positions affecting the forecast of SCE's base rate revenue requirement. As set forth in the March 2003 Joint Comparison Exhibit (Exhibit 403), ORA's base rate revenue requirement recommendation for 2003 is $2.625 billion, or $364 million less than SCE's request.[3] Due to the complexities of calculating revenue requirements reflecting parties' positions on the various underlying components, Exhibit 403 does not include a calculation of the revenue requirement recommendations associated with the positions of Aglet or TURN.

## 2. Preliminary Matters

Our primary task in this decision is determining the just and reasonable base revenue requirement for SCE for the 2003 test year. We accomplish this

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2 Greenlining participated jointly with the Latino Issues Forum. We follow Greenlining's convention of referring to these joint parties as Greenlining.

3 This does not reflect SCE's final recommendation as set forth in the May 2003 update testimony (Exhibit 411), because that exhibit does not include an updated calculation of ORA's revenue requirement recommendation. However, we expect final difference between SCE's and ORA's recommendations to be similar to the $364 million difference calculated in March 2003. This is because the difference between SCE's March 2003 and May 2003 revenue requirement requests is due to updated labor and non-labor escalation rates upon which both parties agree, as set forth in Exhibit 412.

task, as well as the resolution of the other Phase 1 matters at issue, by evaluating and resolving approximately 150 separate issues, most of which were contested. We will first address certain overarching matters that warrant discussion.

### 2.1. The Utility's Showing

In a 1992 SDG&E proceeding, the Commission stated its expectations for utility showings in GRCs:

> The purpose of a general rate case is to develop and adopt sound, informed estimates of the reasonable costs to be incurred in the test year. We know that our adopted levels of revenues and expenses may be at variance with actual experience. However, we must be sufficiently informed to know that adopting a given estimate makes sense. Part of this process involves making sure that we do not repeatedly approve revenues to meet a one-time cost. When a utility's expense estimate includes the performance of a task it had planned to accomplish with previously authorized funds, we will want to know why the utility did not spend its funds as planned the first time around and will be hesitant to charge ratepayers twice for the same expense. In addition, we want to be confident that the activities being undertaken by the utility are lawful and otherwise consistent with public policy. (D.92-12-019, 46 CPUC 2d 538, 555.)
>
> The company often does not even mention the name of major programs or activities and almost never adequately explains its basis for forecasting related costs. The application often makes only a general request for funds without providing a reasonable, well-explained justification.[4] While approving [the settlement at issue in

[4] In an endnote at this point, the Commission further explained the problems it found with SDG&E's initial GRC showing:

> Often, SDG&E simply states that "1988 base year recorded costs were adjusted as follows…" Although this type of explanation might help a reader to understand where the cost figures came from, it does not provide a justification. Why is it appropriate to use a 1988 base year recorded cost for this account? What changes are expected in staffing and

*Footnote continued on next page*

> that decision], we wish to make it clear to SDG&E and other utilities that the initial showing in the current case does not meet our requirements.[5] (*Id.*)

***Discussion***

SCE seems to have taken at least some of the 1992 Commission's concerns to heart in this proceeding. The volume of material that SCE submitted in its direct and rebuttal evidentiary showings was nothing short of massive, and SCE claims that it submitted "the most comprehensive showing SCE has ever made." (SCE Opening Brief, p. i.) SCE states that it submitted more than 5,400 pages of prepared direct testimony (not including rebuttal testimony). For administrative and general (A&G) issues alone, SCE included 1,500 pages of prepared testimony supported by 10,340 pages of workpapers, sponsored by 35 witnesses. In

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> operations? Why are the specified adjustments appropriate? How were they calculated? These types of questions should be easily answered by the initial showing. (*Id.*, 764.)

[5] In an endnote at this point, the Commission elaborated on it expectations for utility showings in GRCs:

> SDG&E's guarded initial showing may be a product of a protective, litigative instinct. All too often, utilities offer only the most minimal support for their rate requests, choosing instead to wait to see what subjects appear to be of interest to DRA [the predecessor organization to ORA]. In response to DRA's concerns, utilities then provide focused rebuttal. (*Id.*)
>
> This strategy may be traditional, but it is not acceptable. Hopefully, the company has done a more complete job of satisfying itself that a given program or expense is worthwhile. We would expect the company to make an equally convincing showing to this Commission when asking to pass those costs through rates. Where a rate case is litigated or a settlement is contested, the utility must provide a more detailed showing for all of its requested revenue requirement, in order to sustain its burden of proof. (*Id.*)

*Footnote continued on next page*

comparison, in its last GRC SCE's showing included 400 pages of prepared A&G testimony by nine witnesses. Moreover, SCE continued to think big when it tendered an 856-page opening brief.[6]

Although we appreciate SCE's apparent attention to the Commission's stated concerns about guarded initial showings, we are compelled to observe that size alone does not constitute fulfillment of the utility's obligation to explain and justify its request. In fact, an overly massive utility showing can obscure the utility's substantial justification for its request (or lack thereof), thereby detracting from the parties' and the Commission's ability to conduct timely review and evaluation. We must question whether it is reasonable to attempt the complete processing of any case with a volume of documentation that even approaches "the most comprehensive showing … ever" within the confines of evolving expectations for the timely conclusion of our proceedings.

Accordingly, we now request that in presenting their initial rate case showings, utilities work to provide the necessary justification with greater attention to the need for economy of words and data. We are not in any way retreating from our policy of requiring better initial utility showings than the one we encountered in the 1992 SDG&E proceeding. We are simply directing utilities to work at being more efficient in their presentations, which in turn should enable the Commission to administer its proceedings with greater efficiency. We invite utilities to consider, for example, whether the inclusion of a wiring diagram that depicts the type of excitation system used at coal-fired generation

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[6] We affirm the ALJ's ruling striking SCE's initially tendered brief and directing SCE to refile the brief subject to a maximum page limitation.

facilities adds needed evidentiary support for their funding requests. (See Exhibit 17, pp. 67, 69.) Elimination of duplicative material may be helpful. (See Exhibit 55, pp. 9, 57.) We also ask that ORA and other intervenors make efforts to ensure that their participation contributes to the efficient processing of our rate proceedings.

ORA reminds us that SCE must meet the burden of proving by clear and convincing evidence that it is entitled to the relief it is seeking in this proceeding, and that the burden is not on ORA or other intervenors to demonstrate that SCE's request is unreasonable.[7] We intend to hold SCE to this standard as we examine individually the myriad components of SCE's request.

As a general matter, with respect to individual uncontested issues in this proceeding, we find that SCE has made a *prima facie* just and reasonable showing unless otherwise stated in this opinion.

### 2.2. SCE's Financial Health

SCE's Chairman and Chief Executive Officer (CEO), Alan J. Forher, testified that in the wake of the California energy crisis that brought SCE to the brink of financial collapse, restoration of investor confidence is essential if the company is to provide the service its customers expect. He went on testify that:

[7] "[T]he long-standing and proper rule [is that a] utility seeking an increase in rates has the burden of showing by clear and convincing evidence that it is entitled to such increase." (D.00-02-046, p. 38, *citing* D.90462, 2 CPUC 2d 89, 98-99.) *See also* D.00-02-046, Conclusion of Law 6. (*Id.*, p. 535, as modified by D.01-10-031, p. 45.)

> Commission general rate case decisions have always been important to investors' assessments of regulatory support for a utility's continued financial well-being. In this instance, Commission approval of SCE's investment and operating plans is especially important to signal a return to the supportive regulation historically found in California. (Exhibit 1, p. 4.)

***Discussion***

We understand that the investment community is vitally interested in the decisions of this Commission. We also recognize that an investor-owned utility's credit rating and its access to capital are of critical importance to its ability to provide the infrastructure it needs to meet its customer service obligations. However, we find no evidence convincing us that granting SCE the full amount of its requested test year base revenue is a necessary precondition for the company to achieve the financial health it requires to provide adequate utility service. To the contrary, evidence introduced by Aglet shows that the company's financial condition has already improved greatly since the height of the state's energy crisis and SCE's financial crisis. Indicators supporting this assessment include an improved credit rating of BB by Standard and Poor's in March 2002, SCE's achievement of certain standards marking progress towards its qualifying for an investment grade rating, the payoff of defaulted obligations, a much-reduced threat of bankruptcy, and the recovery of the PROACT undercollection.

We believe that our actions in response to SCE's financial crisis have been and will continue to be supportive of the utility, and we will consider SCE's creditworthiness as we consider the components of its GRC request. Nevertheless, if we find that SCE has included unnecessary or unreasonable expenses or capital projects in its GRC request, we will not hesitate to exclude the item from ratepayer funding responsibility. Similarly, we will not approve higher depreciation rates than we otherwise would solely in an effort to help SCE achieve a better credit standing. In summary, our concept of "supportive regulation," unlike that of SCE's CEO, apparently, includes support for the interests of ratepayers as well as the interests of the utility and its investors.

### 2.3. Comparative Rate Levels

ORA points out that SCE's rates are among the highest in the nation even without the revenue increase sought by SCE in this GRC. The following facts make ORA's point and expand on it:

1. In 2001, SCE's average residential rate was 13.29 cents per kilowatt-hour (kWh), the California average was 11.40 cents per kWh, and the national average was 8.47 cents per kWh.

2. From 1996 through 2001, SCE's residential rates were between 9% and 18% higher than the California average and 37% to 62% higher than the national average.

3. In 2001, SCE's commercial rates reached 17.04 cents per kWh while the national average was 7.35 cents per kWh.

4. From about 1996 to 2000, SCE's industrial rates stayed at 8.05 cents per kWh, then, in 2001, increased to 12.13 cents per kWh, or about 240% of the national average.

5. In 2001, SCE's residential, commercial, and industrial rates were even higher than those of Pacific Gas and Electric Company (PG&E) and SDG&E, with the exception of SDG&E's residential rates.

6. In 2001, average California rates (including municipal utilities) were 11.4 cents per kWh for residential service, 11.2 cents for commercial service, and 7.6 cents for industrial service. While these averages were considerably higher than national average, they were still low compared to SCE's rates of 13.29 cents, 17.04 cents, and 12.13 cents.

Arguing that high electricity rates are damaging to California's economy and to SCE itself (because some customers are able to bypass SCE's system and will do so if high rates make it cost effective to do so), ORA asks the Commission to look at all rate case increase requests with skepticism, and to adopt only reasonable rates that are supported by record evidence.

***Discussion***

The evidence shows that the electric rates of investor-owned California utilities, particularly those of SCE, are comparatively high by several standards, and that ratepayers and the California economy are being harmed by these high rates. SCE's attempt to change the topic to customer bills rather than high rates does not change this fact, nor does SCE's attempt to assign part of the blame for high rates to the Division of Ratepayer Advocates (DRA), ORA's predecessor. ORA has also demonstrated that SCE's high rates add to the threat of utility bypass in various forms such as municipalization, firms moving operations out of the utility's service territory, and self-generation, and that residential ratepayers who have fewer alternatives to utility service are the most threatened by bypass.

Of course, most of the rate comparison data supplied by ORA pertains to the year 2001, a time of unprecedented electricity market disruptions and extraordinarily high commodity prices. It must be recognized that the high rate problem in 2001 was in large part a reflection of the commodity market conditions of that time. Indeed, while SCE's base rate revenue requirement is substantial, and determining its appropriate level is the major undertaking of this GRC, it is worth noting that the outcome of this proceeding can at best provide only a partial solution to the high rate problem. This can be seen by comparing the difference between SCE's and ORA's revenue requirement recommendations ($364 million) with the consolidated revenue requirements of $8.472 billion being paid by SCE's customers, as set forth in D.03-07-029. Even if ORA's revenue requirement recommendation were adopted in full, SCE's electric rates might remain high by national standards.

Regarding the high rate problem, ORA witness Phan testified that "[a] regulated utility will continue to expand its services, personnel, rates, and revenues until and unless it is halted from the outside." (Ex. 113, p. 2-13.) In the context of this GRC proceeding, we see our role as providing such an "outside" check by conducting a thorough review of SCE's request and, as discussed earlier, holding SCE to its burden of proving that its revenue requirement request is justified. In this manner, we ensure that SCE's revenue requirement is set at a level that does not contribute unnecessarily, if at all, to the high rate problem.

### 2.4. Forecasting Issues

A central feature of conventional cost-of-service method of ratemaking is forecasting future test year costs using historical cost information as well as current information regarding the utility's operational and investment plans. In this section, we address general principles applicable to forecasts of both expenses and capital expenditures.[8]

#### 2.4.1. Averaging and Other Methodologies

Several different methods can be used to calculate test year estimates of expenses. These include linear trending, averaging, last recorded year, and budget based estimates. In PG&E's 1999 GRC, the Commission summarized certain methodological issues as follows:

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[8] Unless indicated otherwise, references to Operations and Maintenance (O&M) expenses are in year 2000 dollars and references to capital expenditures and capital plant additions are in nominal dollars.

> The Commission has recognized that there are different valid and acceptable methods for account-by-account forecasting test year costs in a GRC, including using a single recorded year's expenses . . . and using multi-year average recorded costs . . . . The question at hand is which of these two methods yields the most accurate and reliable forecast of test year expenses. In PG&E's test year 1990 GRC the Commission described the following criteria for developing a base estimate of test year expenses:
>
> If recorded expenses in an account have been relatively stable for three or more years, the 1987 recorded expense is an appropriate base estimate for 1990.
>
> If recorded expenses in an account have shown a trend in a certain direction over three or more years, the 1987 level is the most recent point in the trend and is an appropriate base estimate for 1990.
>
> For those accounts which have significant fluctuations in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility, an average of recorded expenses over a period of time (typical four years) is a reasonable base expense for the 1990 test year. (D.89-12-057, 34 CPUC 2d 199, 231.)

With respect to a particular account in that GRC (Account 588), the Commission went on to state:

> Absent a specific explanation of why 1987 recorded data best reflects the estimated 1990 expenses of an account with fluctuating expense levels and no discernible trends, we find it most appropriate to use a four-year average as the base 1990 estimate. (*Id.*, 238.)
>
> (*Re Pacific Gas and Electric Co.*, D.00-02-046, pp. 156-157 (*quoting,* D.89-12-057, 34 CPUC 2d 199).)

While the foregoing passage arose in the context of electric distribution expenses, the principles are consistent with findings the Commission has made in the context of other expense categories. For example, the Commission addressed forecasting methodologies in a 1989 decision on a water utility's request for a rate increase:

> Where it is clear that there is a trend of increasing expenses which cannot be explained by inflation alone, and that such increases are necessarily incurred in providing utility service, less weight should be given to the constant dollar averaging method. On the other hand, where it appears that an expense category is subject to year-to-year variations, constant dollar averaging may be a more appropriate method to smooth out such variations. (*Re California Water Service*, D.89-04-060, 31 CPUC 2d 481, 506.)

***Discussion***

The forecasting principles discussed in D.00-02-046, D.89-12-057, and D.89-04-060, quoted above, are generally appropriate and applicable here. Many accounts reflect significant spending fluctuations from year to year, and in the absence of information to the contrary (for example, information that expenses have been stable over time and no discernible upwards or downwards trend exists), we would ordinarily expect a multi-year average of recorded data to yield a more reliable forecast than a forecast predicated upon a single year's data. Also, because utility spending plans may not always be implemented as intended, budget-based forecasts generally will be given less weight than forecasts based on recorded spending in the absence of a showing supporting the contrary approach. For ongoing functions, a multi-year spending pattern, as reflected in the recorded books of account, suggests a utility's willingness and ability to commit to a budgetary plan on a sustained basis.

#### 2.4.2. Capital Expenditures & PBR

Aglet raises two forecasting issues associated with the utility's return to cost-of-service ratemaking. First, Aglet takes issue with SCE's position that capital spending associated with a program to replace aging distribution assets

(Infrastructure Replacement Program or IRP) was not reflected in rates in recent years. Aglet acknowledges that IRP costs were not explicitly included in the base revenue requirement that formed the starting point for SCE's PBR mechanism. However, Aglet disputes any contention that this means that SCE has been unable to recover its IRP costs under PBR. This is because under PBR, where allowable capital costs are based on a formula and are not tied to specific projects, there is no way to determine with any precision what capital-related costs are included in rates. At the same time, Aglet contends that in light of the well-settled regulatory principle that utilities are not required to make specific expenditures in exactly the same manner and amounts that underlie authorized rates, it is reasonable to assume that all incurred costs are included in rates even when the utility spends more than the authorized revenue requirement.

Moreover, Aglet notes that SCE recorded positive earnings in most quarters that its PBR mechanism was in effect, suggesting that the company recovered its operating expenses, depreciation, and tax costs during that period. Accordingly, Aglet urges that in determining the need for increased capital costs for the IRP, we should recognize that present rates have recovered ongoing capital-related costs of plant installed to date.

Second, Aglet asks that we recognize that in recent years under PBR, SCE has had an incentive to recover capital-related costs in rates while not actually spending on the IRP. Aglet urges that given the existence of this incentive, we should be very cautious in approving additional capital costs for improvements that were deferred during the SCE financial crisis.

***Discussion***

We accept as valid the theory that capital expenditures such as those associated with the IRP have been included in rates during the term of SCE's PBR mechanism. To assume otherwise would require acceptance of the unreasonable and unproven hypothesis that SCE's PBR mechanism failed to provide the level of revenues needed by the utility to meet its service obligations. With the return to conventional cost-of-service ratemaking, this theory requires that we carefully review the incremental capital expenditures for which SCE seeks recovery. In particular, we will seek reasonable assurance that ratepayers do not contribute twice for the capital-related costs of installed plant. Moreover, as discussed in Section 3 of this decision, this theory applies as well to the return of SCE's nuclear generation from incentive to conventional cost-of-service ratemaking.

Aglet has also shown that SCE had an incentive to defer capital expenditures with the expectation of a return to cost-of-service ratemaking. We will heed Aglet's call for caution in reviewing deferred projects. However, if a deferred project is reasonably calculated to enable the utility to provide safe and reliable service on a cost-effective basis, ratepayers have not already paid for it, and the deferral did not cause cost increases that could have reasonably been avoided, we will not deny funding for that project solely because it has been deferred.

#### 2.4.3. Witness Qualifications

In rebuttal testimony an SCE witness suggested "that judgment, experience, training and education are required to make an informed decision regarding forecasts." (Exhibit 299, p. 55.) SCE makes similar statements elsewhere in its testimony.

***Discussion***

We accept this proposition, but we reject any implication that such qualifications are the exclusive province of utility witnesses, who will invariably have the most intimate knowledge of their area of operations. In other words, ORA and intervenor analysts are entitled to offer and have us consider their expert opinions based on informed judgment, even if they have never been employed by a public utility.

Selecting the most appropriate method to forecast test year expenses is ultimately a matter of informed judgment, and whether a witness is employed by a utility or an intervenor, the exercise of judgment might be influenced by a concern for results. With this in mind, we will carefully review each witness's underlying assumptions, analysis and logic before accepting the forecast recommended by that witness.

## 3. Generation

SCE retains interests in nuclear, coal, and hydroelectric generation facilities. SCE seeks base rate recovery of the costs of these assets, excluding fuel costs recovered through the Energy Resources Recovery Account (ERRA) mechanism. SCE also requests rate recovery of certain 1997-98 capital additions, consideration of which was transferred from A.99-04-024 to this case.

### 3.1. San Onofre Nuclear Generating Station

SCE owns a 75.05% share of San Onofre Nuclear Generating Station (SONGS) Unit Nos. 2 and 3 and is also the operating agent for those units. SCE also owns 80% of SONGS Unit No. 1, which has been permanently shut down. In D.96-04-059, the Commission adopted the Incremental Cost Incentive Pricing (ICIP) ratemaking mechanism for SONGS 2 & 3, a form of PBR under which SCE recovers incremental operational costs through a cents-per-kWh payment. The ICIP mechanism will continue in effect until December 31, 2003, after which SONGS 2 & 3 will return to cost-based ratemaking consistent with D.01-01-061 and D.01-05-035. No party contests SCE's proposed framework for conventional cost-of-service ratemaking for SONGS 2 & 3.

### 3.1.1. SONGS 2 & 3 Capital

#### 3.1.1.1. Introduction

For SONGS 2 & 3 plant that will be placed in service in 2004 and 2005, SCE forecasts capital expenditures (excluding corporate overheads) of $81.7 million in 2004 and $63.2 million in 2005. SCE's share of those expenditures, which reflects its 75.05% plant ownership share, is $61.3 million in 2004 and $47.5 million in 2005. SCE reduced its estimate for the Used Fuel Pool Rack Modification by $520 thousand in 2004 and by $571 thousand in 2005 upon accepting ORA's position on that project. SCE's total capital expenditure forecast is reduced accordingly.

ORA proposes the inclusion of capital expenditures (SCE share) totaling $41.1 million in 2004 and $33.2 million in 2005. Compared to SCE's forecast, ORA's estimates represent reductions of $19.7 million in 2004 and $13.6 million in 2005. As shown in Exhibit 403, TURN proposes reductions to SCE's forecast of $17.9 million for Marine Mitigation, $25.7 million for Used Fuel Storage, and $1.9 million for Blanket Work Orders. The total difference between TURN and SCE is $45.5 million (SCE share) for the two years.

#### 3.1.1.2. Forecasting Methods

SCE contends that the correct way to forecast the SONGS 2 & 3 capital budget is to make a project-by-project investigation of the actual work to be performed. SCE's forecast reflects this methodology.

For its forecast, ORA used both averaging and project-specific information. ORA used five years of historical data (1996-2000) to estimate expenditures for those capital additions that will be basically the same from year to year. For two projects that ORA found to be fully vetted and approved through SCE's internal processes, the SONGS 2 & 3 Used Fuel Storage Project and Cycle 13 Used Fuel

Rack Modifications, ORA used project-specific information to develop its forecast. ORA recommends disallowances for two other projects: Wetlands Reclamation ($9 million for 2004 and $9 million for 2005, SCE share), and Replacement of Offsite Sirens/Monitors ($2.7 million for 2004 and $300 thousand for 2005, SCE share).

TURN objects to SCE's forecast on the grounds that SCE substantially underspent on planned capital additions during the ICIP period, and that the company's project-specific forecast amounts to double charging ratepayers for certain activities that were planned in the past and included in ICIP rates. SCE spent $182 million during the 1996-2003 ICIP period, or approximately 36% of the $510 million forecast used in the establishment of the ICIP mechanism. The actual spending was an average of $22 million per year during this period, and the highest annual spending was approximately $36 million in 1998. In view of this underspending of nearly $330 million for the eight-year ICIP period, TURN submits that SCE's proposal to more than double the average spending of the ICIP period is unjust and inequitable.

SCE acknowledges that recent historic averages of capital expenditures for SONGS 2 & 3 can provide a helpful comparison for forecast capital expenditures levels, but it claims that ORA's forecast fails to provide sufficient funding for projects necessary for continued safe, compliant, and reliable operation. In addition, SCE finds fault with ORA's averaging methodology because it failed to escalate capital expenditures to constant 2000 dollars prior to applying the five-year average methodology. According to SCE, correcting this methodological error changes ORA's recommendation for SONGS 2 & 3 capital funding to $60.1 million for 2004 and $50.7 million for 2005 (nominal dollars at 100% level).

***Discussion***

A forecast that reflects the company's actual plans for future capital expenditures might seem to be more reliable than a forecast that is based solely on the level of past investments. After all, the utility experts having the most detailed knowledge of operational requirements should be in the best position to know what capital additions are needed for future operations and what their costs are.

However, utility spending plans are not necessarily carried out. In the first place, there is no specific obligation under conventional cost-of-service or incentive ratemaking to spend budgeted amounts during the relevant time period. Moreover, as SCE witness Perez stated:

> SCE cannot rigidly "fix" the detailed specific scope of capital work to be implemented in future years. SCE requires flexibility to optimally respond to changing NRC requirements, plant reliability or operability changes, results of studies and conceptual or preliminary engineering, industry developments, replacement energy costs, and other evolving factors. (Exhibit 9, p. 4.)

Given these many reasons why spending plans may not be carried out, regardless of how much site-specific expertise went into the making of those plans, a utility's budget-based forecast may actually be less reliable than a forecast based on historical spending data. Historical spending patterns reflect not only past spending plans, but also the utility's willingness and ability to carry out those plans. It is instructive that SCE had forecast capital spending of $510 million during the 1996-2003 period for the purpose of establishing the ICIP mechanism, but it actually will have spent just slightly more than a third of the forecast amount. Also, as ORA notes, SCE's budget-based forecast of

SONGS 2 & 3 capital expenditures represents more than a doubling of the 1996-2000 average level of expenditures. Specifically, SCE forecasts spending increases of 162% above the five-year average for 2004 and 103% above the average for 2005.

Rebutting TURN's position on SCE's underspending pattern, and TURN's related contention that SCE's forecast would lead to double charging ratepayers for the same investments, SCE goes to great lengths to explain the history of the ICIP mechanism. SCE focuses on the fact that the mechanism eliminated retrospective reasonableness reviews of SONGS capital expenditures, and claims that TURN is attempting to institute an impermissible review of the timing of certain SONGS 2 & 3 expenditures in this proceeding. SCE is missing the point of TURN's analysis, which is to determine the reasonableness of forecast expenditures by, among other things, determining whether it can reasonably be concluded that ratepayers have already paid, in whole or in part, for such expenditures. This is a legitimate inquiry that does not in any way represent an after-the-fact reasonableness review precluded by the ICIP mechanism. We find that TURN has raised a valid point, i.e., ratepayers have already made contributions to the Used Fuel Storage and Marine Mitigation projects through the ICIP rates.

All of these factors support the use of an average of actual expenditures as being more reliable than a straight budget-based forecast of SONGS 2 & 3 capital expenditures, and disallowances for specific projects to the extent necessary to prevent double charging ratepayers for those projects. While SCE has provided a substantial amount of material to justify various SONGS 2 & 3 projects included in its capital forecast, it has not convinced us that it is reasonable to (1) ignore its spending history, (2) assume that all of the justified projects will be carried out in

2004 and 2005 as planned, and (3) assume that ratepayers have contributed nothing to any of the deferred projects during the ICIP period.

We will therefore adopt ORA's blended forecasting approach as the more reliable method for determining SONGS 2 & 3 capital spending in this GRC. However, we do not adopt ORA's specific capital spending recommendations. First, ORA's averaging approach requires correction to account for the effects of inflation. Also, we do not adopt all of ORA's project-specific recommendations, and we adopt adjustments based on TURN's recommendations. We turn our attention to these project-specific recommendations, and then we present our adopted forecast for SONGS 2 & 3 capital expenditures.

#### 3.1.1.3. Used Fuel Storage Project

SCE projects that the SONGS 2 & 3 fuel pools will run out of space in July 2007 and March 2008, respectively. Construction of a temporary Used Fuel Dry Storage Facility (dry cask storage) will provide necessary onsite spent fuel storage capacity. SCE forecasts that it will incur capital expenditures of about $34 million (nominal dollars, 100% level; SCE's share is $25.7 million) for the Used Fuel Storage project in 2004 and 2005.

Based on its position that ICIP rates have already fully covered the costs of the project, TURN recommends a disallowance of the entire $25.7 million sought by SCE.

***Discussion***

SCE identified a used fuel storage project that it planned to build during the ICIP period, but the project was deferred. While we reject any assumption that ratepayers will have contributed nothing to projects such as the Used Fuel Storage project during the ICIP years, we are not prepared to accept TURN's opposite assumption that ratepayers have fully paid for the project's capital costs.

Nothing in the decisions leading to the establishment of the ICIP mechanism suggests such precise attribution of the ICIP rate to specific projects is warranted. TURN's proposal to explicitly disallow the entire amount of SCE's projected costs for the Used Fuel Storage project is denied. Because it is reasonable to determine that ratepayers have made contributions to the cost of this project, but it is impossible to calculate the precise amount of that contribution, the fairest outcome is to assign equal cost responsibility for remaining costs of the project. Accordingly, we allow 50% of SCE's forecast cost.

#### 3.1.1.4. Marine Mitigation Projects

SCE is required to mitigate impacts on the marine environment in compliance with the Coastal Development Permit (CDP) issued by the California Coastal Commission (CCC) for SONGS 2 & 3. These mitigation requirements include development and implementation of a wetland restoration project to mitigate fish losses and construction of an artificial kelp reef to mitigate impacts on the San Onofre kelp reef. SCE forecasts that it will spend $13.2 million in 2004 and $20 million in 2005 on marine mitigation projects (nominal dollars, 100% level; SCE's share for both years is $24.9 million).

TURN proposes a disallowance of $17.9 million, or all but $7 million of the $24.9 SCE forecast for marine mitigation. TURN does so to prevent SCE from recovering the same mitigation costs twice. TURN contends that the ICIP rates provided for the recovery of $75 million in marine mitigation costs, and that the forecast underlying the ICIP mechanism estimated that $7 million would be spent after 2004.

ORA proposes disallowances of $9 million in 2004 and $9 million in 2005 associated with the restoration of 20 acres of wetlands at San Dieguito.

***Discussion***

As with the Used Fuel Storage project, TURN's recommended disallowance is based upon the assumption that ratepayers have already paid for the work (all but $7 million) during the ICIP period. Again, we are not prepared to make such an assumption, and we therefore deny the recommended disallowance. It is more reasonable to assume that a portion of the ICIP rate was associated with marine mitigation costs, and that the use of a forecast that assigns equal ratepayer and shareholder responsibility for remaining costs strikes the most reasonable balancing of interests.

SCE has shown that ORA's recommended disallowances associated with 20 additional acres of wetlands restoration at San Dieguito is inappropriate because the restoration has no effect on customer rates. This proposed disallowance will not be approved. The amounts in question ($18 million for 2004 and 2005, SCE share) are for the mandated restoration of 150 acres at the San Dieguito site.

#### 3.1.1.5. Offsite Sirens and Monitors Project

SCE's capital expenditure forecast includes $3.935 million (nominal dollars, 100% level; SCE's share is $2.953 million) for replacement of off-site sirens and monitors in 2004 and 2005. SCE originally installed the off-site siren system in 1982, and determined it needed replacement when it showed visible signs of deterioration and spare components were no longer available from the manufacturer. In addition, the software for the monitoring system is no longer supported by its manufacturer. In 1999, SCE commenced a program to replace the off-site siren system, even though it was then, and remains today, fully functional and consistent with regulatory requirements.

ORA asserts that SCE unreasonably deferred the off-site siren and monitor replacement project to 2004 and 2005, and should have performed it earlier. ORA therefore proposes the removal of the forecast cost of the off-site sirens and monitors from SCE's capital expenditure forecast for SONGS 2 & 3.

***Discussion***

The evidence does not support a conclusion that SCE unreasonably, and without cause, deferred this necessary project to the test period. In fact, SCE began investing in the off-site sirens and monitoring replacement project in late 1999 under the SONGS 2 & 3 ICIP rate mechanism. SCE's requested funding for the off-site siren and monitoring replacement project is essential to providing a seamless transition to the new system without risking public health and safety, and should be allowed in rates.

#### 3.1.1.6. Blanket Work Orders

TURN recommends disallowances of SCE's increased spending on several small work orders, including tools and equipment, computers, office equipment, facilities, and spare parts. As shown in Exhibit 403, TURN's recommendation would result in a disallowance of $1.9 million.

***Discussion***

TURN's analysis is not without merit. However, we are adopting ORA's forecast methodology, which relies on the averaging of historical expenditures, which in turn results in disallowances of certain of SCE's proposed expenditures. We will not order additional disallowances for capital expenditures that are covered by ORA's forecast. Doing so could result in an unfair duplication of disallowances.

#### 3.1.1.7. Conclusion – SONGS 2 & 3 Capital Expenditures

Applying ORA's blended forecasting approach, the corrections set forth in Exhibit 280, Appendix B, and the project-specific determinations discussed above, we adopt the following capital expenditures forecast for SONGS 2 & 3 for 2004 and 2005:

**SONGS 2 & 3 Adopted Capital Expenditures**
**($1,000)**

| | |
|---|---|
| 2004 | |
| Special Projects | |
| Used Fuel Storage (50% of 22,325) | 11,163 |
| Marine Mitigation (50% of 13,200) | 6,600 |
| Used Fuel Pool Rack Modifications | 1,206 |
| Offsite Sirens and Monitors | 3,635 |
| All Other Projects | 36,568 |
| Total @ 100% of cost | 59,172 |
| SCE Share (75.05%) | 44,409 |
| | |
| 2005 | |
| Special Projects | |
| Used Fuel Storage (50% of 11,860) | 5,930 |
| Marine Mitigation (50% of 20,000) | 10,000 |
| Used Fuel Pool Rack Modifications | 1,239 |
| Offsite Sirens and Monitors | 300 |
| All Other Projects | 37,575 |
| Total @ 100% of cost | 55,044 |
| SCE Share (75.05%) | 41,311 |

### 3.1.2. SONGS 2 & 3 Base O&M Expenses

#### 3.1.2.1. Introduction

Although SONGS 2 & 3 will not be returned to conventional cost-of-service ratemaking until 2004, SCE presented its O&M forecast for 2003 with the intent that it will be escalated to 2004 and 2005 levels. SCE at first forecast O&M costs of $147.8 million for SONGS 2 & 3 in 2003 (2000 dollars, SCE share). In its May 2003 update testimony, SCE increased its forecast to $148.4 million to reflect the cost of increased annual fees assessed by the Nuclear Regulatory Commission (NRC). This forecast is for what SCE considers to be base O&M, i.e., for normal plant operations. It excludes refueling and maintenance outage-related O&M costs, the amount and the recovery of which are addressed in Section 3.1.3.

SCE developed its base O&M forecast by analyzing recorded costs for the years 1996-2000, making 34 "historical" adjustments to remove cyclical and unusual expenses incurred during the recorded period, and making 11 "future" adjustments to incorporate anticipated cyclical and unusual activities and expenses. It then selected what it considered to be the appropriate method for converting the recorded/adjusted data into test year forecasts for various functions and accounts, as described below.

SCE manages SONGS 2 & 3 in accordance with eleven functional groups: Operations, Maintenance, Engineering, Site Projects, RadChemical Control, Regulatory Affairs, Security, Training, Nuclear Support, Corporate Support, and Participants. To reconcile this breakdown of functions with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, SCE organized O&M costs by these functional groups and then, within each such group, by FERC Account. Using the recorded/adjusted costs for 49 of these functional group/FERC account pairings, SCE developed labor, non-labor, and other cost estimates for each such pairing using a forecast method such as last recorded year; three-, four-, or five-year averaging; and three-, four-, or five-year linear trending.

ORA recommends several revisions to SCE's base O&M forecast. In combination, ORA's recommended adjustments result in a forecast of $130.4 million (2000 dollars, SCE share), or $17.4 million less than SCE's "pre-update" forecast of $147.8 million. TURN recommends a reduction of $1.7 million (2000 dollars, 100% share) for an adjustment related to workers' compensation claims.

In the remainder of Section 3.1.2 of this decision, we address issues that affect the parties' base O&M expense forecasts, including disputes over adjustments and forecast methods. Unless otherwise indicated, dollar figures in the following discussion are in 2000 dollars, 100% share. Also, some dollar figures stated below represent record evidence that predated submission of the Joint Comparison Exhibit (Exhibit 403) and the update testimony (Exhibit 411). Notation is made where these dollar figures are revised or updated in Exhibits 403 or 411.

#### 3.1.2.2. Training Credits Adjustment

In this historical adjustment (Adjustment #20), SCE removed credits to its training program received from the State of California as part of its Employment Training Program (ETP). The ETP provides for training for workers facing layoff because of technological advances and foreign and domestic competition. During the period May 1998 through May 2000, SONGS 2 & 3 was eligible to participate in ETP because it was facing out-of-state domestic competition. According to SCE, SONGS 2 & 3 is no longer eligible to participate in the ETP because, with the return to the cost-of-service ratemaking, it is no longer confronted with out-of-state domestic competition.

Noting that SCE has not opted out of the ETP altogether, ORA proposes to disallow this adjustment. This would reduce SCE's O&M forecast by $367,000.

***Discussion***

The evidence shows that SCE is ineligible to participate in the ETP with the return of SONGS 2 & 3 to cost-of-service ratemaking. Since SCE cannot participate in the program, it would be unreasonable to establish the authorized revenue requirement on the basis of an assumption that it will continue to receive credits from the program. ORA's proposed disallowance of this adjustment is rejected.

#### 3.1.2.3. Deferred Activities Adjustment

ORA takes issue with SCE's Adjustment #30, which SCE made to account for certain deferred O&M projects. This historical adjustment is not described in SCE's direct testimony on generation. ORA describes the adjustment, and its position regarding the adjustment, as follows:

> Adjustments #29 and #30 refers (sic) to expenditures incurred for the [Year 2000 (Y2K)] project. In Adjustment #29 SCE removes these one-time Y2K support costs from the 1998 through 2000 historical recorded period. However, in Adjustment #30 "Y2K Replenishment of Nuclear Support Costs & Deferrals" SCE restores these same amounts and adds additional amounts borrowed from other departments to deal with Y2K. It states that "to create funding for the Y2K project, SCE required business units to reduce their O&M expenditures. This one-time event resulted in deferral of work to be performed in the future." [Footnote omitted.] SCE provided no specific information on "deferred work" and furthermore stated that "all of the deferred activities are now complete." [Footnote omitted.] Accordingly, ORA disagrees with the inclusion of historical adjustment #30. However, ORA concurs with Adjustment #29. (Exhibit 113, p. 7-B-11.)

ORA's recommendation to exclude Adjustment #30 results in a reduction of forecast costs of $2.021 million.

***Discussion***

SCE does not take issue with ORA's assertion that SCE failed to provide specific information on the work deferred as a result of the Y2K project. Moreover, SCE does not deny that such project-specific information is important to the analysis of the adjustment. It is presumably for this reason that SCE chose to present a list of such projects in its rebuttal testimony.

SCE's rebuttal testimony shows that SCE deferred 16 specific projects plus miscellaneous work totaling $8.8 million during the period 1998-2000. SCE indicates that if it were not for the diversion of personnel to the Y2K project, it would have performed work on the 16 projects during the period, and the recorded costs would have reflected the costs of doing so. SCE states that all of the deferred work is now complete. SCE likens the need to resume work on these projects to the need to resume a regular oil change schedule on a vehicle on which a particular scheduled oil change was deferred.

SCE's direct evidentiary showing on this issue falls short of sustaining the company's burden of proof. SCE's witness testified that Adjustment #30 added the cost of the Y2K project back to the company's historical costs. In other words, it is a proxy for the costs of the deferred projects. A mere list of projects, presented for the first time for purposes of rebutting ORA's testimony, does not demonstrate why it is appropriate to use Y2K costs as a proxy for those projects' costs, nor does it demonstrate that SCE's "oil change" analogy is apropos. ORA's proposal to exclude Adjustment #30 is adopted.

#### 3.1.2.4. Awards and Recognition Adjustment

ORA proposes an adjustment to remove the costs of an employee awards and recognition program from the historical recorded period (1996-2000). ORA objects to the inclusion of these costs because, according to ORA, they are for rewards set by SCE management and shareholders, and they are based on criteria devoid of ratepayer input. In response to a data request by SCE, ORA stated that it views the program as no more than social/cultural activities having no bearing on standard O&M functions. ORA construes the inclusion of these expenses as an involuntary levy on ratepayers of the sort prohibited by Commission policy set forth in D.67369.[9]

SCE opposes ORA's proposed adjustment, which would result in a reduction to SCE's forecast of $476,000.

***Discussion***

The SONGS 2 & 3 awards and recognition program provides employees with incentives to perform above and beyond already high performance standards. Such a program is consistent with current human performance theories and is utilized at many corporations. ORA has not shown why ratepayer input is a necessary condition for ratepayer funding for the program. Even though ratepayer dollars may be involved, SCE management is entitled to a reasonable degree of discretion in determining how to motivate employee performance. Moreover, the costs at issue are not so large as to warrant a cost-benefit analysis to determine the program's effectiveness.

It is well established that dues, donations, and contributions are not eligible for ratepayer funding. However, the record evidence establishes that the awards and recognition program includes no such costs. Moreover, there is no basis for concluding that the SONGS 2 & 3 employee awards and recognition

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[9] After reviewing Pacific Telephone and Telegraph Company's contributions to United Fund, Community Chests, the Red Cross, colleges and universities, hospitals, and cultural organizations; and dues to chambers of commerce and service clubs, the Commission declared that "[r]atepayers should be encouraged to contribute directly to worthy causes and not involuntarily through an allowance in utility rates." (62 CPUC 775, 852.) The Commission then stated "it shall be the policy of this Commission henceforth to exclude from operating expenses for rate-fixing purposes all amounts claimed for dues, donations, and contributions." (*Id.*, 852-53.) The California Supreme Court upheld this policy in *Pacific Tel. & Tel. Co. v. Public Util. Comm.* (1965) 62 Cal 2d 634, 669.

costs are in any way equivalent to chamber of commerce dues or charitable contributions. To the extent that ORA's proposed disallowance relies upon the Commission's policy set forth in D.67369, it is without merit. SONGS 2 & 3 employees, and reasonable incentives to motivate their superior performance, are not just a "worthy cause" to which ratepayers might want to contribute separate and apart from utility rates. ORA's proposed adjustment will not be approved.

#### 3.1.2.5. Nuclear Rate Regulation

When SONGS 2 & 3 ICIP ratemaking was implemented in April 1996, SCE no longer needed the SONGS Nuclear Rate Regulation (NRR) group that prepared GRC information and attrition year filings, and provided other support for Commission proceedings. SCE therefore eliminated the NRR group, and, with the exception of 1996, the recorded data from 1996 to 2000 do not reflect the costs of NRR. With the return of SONGS 2 & 3 to cost-of-service ratemaking in January 2004, SCE will once again fund NRR activities.

SCE's Adjustment #38 incorporates into the 2003 O&M forecast SCE's $776,000 estimate of funding needed for preparing testimony, responding to data requests, meeting with ORA and intervenors, preparing for and attending hearings, and interfacing with other SCE departments to prepare justification for O&M expenses and capital additions.

ORA does not take issue with the need to recognize the resumption of work on rate regulation, but it disputes the amount of Adjustment #38. ORA used a five-year average of NRR costs from 1992-1996, the most recent pre-ICIP five-year period of SONGS 2 & 3 cost-of-service ratemaking, to determine an adjustment amount of $552,000. This is a difference of $224,000 from SCE's forecast.

***Discussion***

Although an averaging-based forecast might be more reliable than SCE's estimate, in this case it is based on incomplete cost data. During the 1992-1996 period, SCE utilized some SONGS 2 & 3 personnel to perform work for NRR who were temporarily "matrixed" to NRR. SCE did not charge the costs of the matrixed personnel to NRR accounts and consequently did not identify them as NRR costs. Because the 1992-1996 NRR expenditures do not include these matrixed personnel costs, the averaging methodology does not capture all of the NRR costs from the earlier period, rendering it less reliable. We will therefore approve SCE's proposed Adjustment #38.

#### 3.1.2.6. Site Projects

SCE funds certain SONGS 2 & 3 activities through the Site Projects Functional Group. The Site Projects budget includes major O&M activities that are not required as a part of routine plant operations, occur on a cyclical basis, or require special focus. The majority of the O&M expenses for this group are for projects developed in response to employee Action Requests, and the projects typically result in design modifications to the plant. The scope and quantity of these projects can vary from year to year.

SCE chose the last recorded year method (2000) to forecast test year 2003 costs for the Site Projects Functional Group. SCE also determined that it will need additional funds to implement the Site Projects that are forecast for 2003. SCE's Adjustment #39 identifies the net increase between the last recorded year and the company's estimate for Site Project work activities in 2003. SCE estimates that $12.460 million will be needed in 2003 for Site Projects (consisting of $6.390 million in FERC Account 517 and $6.070 million in FERC Account 532). This represents an increase of 23% from 2000 expenditures.

ORA takes issue with SCE's selection of the last recorded year to forecast the test year expense for site projects as well as SCE's Adjustment #39. ORA instead used a five-year average (1996-2000) of historical expenditures based on its determination that averaging is more appropriate for capturing annual variations. This yields an estimate of $7.517 million ($4.843 million in FERC Account 517 and $2.674 million in FERC Account 532), which is $4.943 million less than SCE's request.[10] ORA objects to Adjustment #39 because, among other things, Site Projects identified by SCE have not been approved by the Site Integrated Project Committee (SIPC) even though the SIPC is responsible for approving and prioritizing the projects. ORA also notes that there has been confusion over which projects should be covered by base funds and which ones by Site Projects funds, there has been considerable underspending in the past three years, and underruns due to uncommitted funds are allocated to a contingency fund. ORA further notes that SCE did not provide detailed project outlines with cost breakdowns for ORA review. ORA concludes that SCE has not substantiated the need for Adjustment #39.

***Discussion***

At issue is whether SCE's budget-based forecast of Site Projects expenditures or ORA's averaging approach produces a more reliable estimate for the test year. We first note that, as SCE's own testimony and the following table show, Site Projects O&M expenses can vary from year to year:

**Site Projects O&M Expenditures**
**(2000 Dollars X 1000, 100% Level)**

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[10] The Joint Comparison Exhibit shows SCE's forecast as $11.550 million instead of $12.460 million, and a difference of $4.033 million. (Exhibit 403, p. 94.)

| 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2001 | 2002 | 2002 |
|---|---|---|---|---|---|---|---|---|
| 5,234 | 4,773 | 13,248 | 8,779 | 10,103 | 11,100 | 10,000 | 13,050 | 15,973 |
| Recorded / Adjusted | | | | | Budget | Rec. | Budget | Rec. |

Sources: Exhibit 7, Tables VIII-3 and VIII-4; and Exhibit 283, Tables II-2 and II-3.

Given the year-to-year variability displayed in this table, an averaging approach should produce a more reliable forecast in the absence of information explaining why any single recorded year or a departmental budget produces a better estimate of future spending. SCE's rebuttal testimony makes several points in an effort to provide such information, but, as discussed below, it fails to make a convincing case for rejecting averaging.

First, SCE contends that ORA's averaging-based forecast does not recognize recent recorded expenditures. Apart from the fact that SCE's direct testimony also did not recognize recent expenditures, since SCE based its O&M forecast on 1996-2000 data plus budget-based adjustments, this contention does not explain why recent expenditures are more predictive than those of prior years. In fact, reliance on recent years may be particularly problematic given ORA's finding of possible past underspending.

Second, SCE states that it needs flexibility in the project implementation schedule; that work scope is contingent upon plant conditions, needs, and evolving regulations; and that adherence to budgets never interferes with regulatory compliance and safety requirements. If anything, this testimony supports the proposition that departmental spending plans may not always be the best predictors of actual future spending.

Third, SCE states that the five-year average of recorded spending from 1998 through 2002 is $12 million, which it asserts is consistent with its forecast of

$12.460 million.[11] However, this does not explain why the 1998-2002 period is more predictive than the 1996-2000 period.

Fourth, to counter ORA's testimony regarding the lack of approval for all projects underlying Adjustment #39, SCE states that each identified project now has approval for engineering analysis and most projects have final approval. However, SCE is unwilling to claim that all of the projects have been approved, and it does not state the dollar value of those projects or the minority of projects that have not been approved.

Finally, noting that it spent approximately $3 million more than it planned to spend in 2002, largely due to a $2.4 million gantry crane project that "emerged" after the budget was approved in January 2002, SCE contends that similar emergent projects can be expected in future years. This last point is at best incomplete, as SCE fails to explain why projects with expenses of such magnitude did not emerge during the historical period.

We will reject SCE's budget-based forecast because the company has not shown that it is more predictive than an averaging forecast. However, we find that ORA's five-year average gives insufficient weight to what may be an increasing trend in this functional group. We will instead adopt a forecast based on a three-year average (1998-2000) as shown in the following table:

**Adopted Site Projects O&M Forecast**

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[11] Table II-2 of SCE's rebuttal testimony (Exhibit 283) shows Site Projects expenditures of $13, $9, $10, $10, and $16 million in 1998, 1999, 2000, 2001, and 2002, respectively. The average is $11.6 million, which SCE rounds to $12 million in Table II-2. If greater precision is applied in lieu of SCE's convenient rounding convention, the five-year average selected by SCE is not quite as consistent with its budget-based forecast as the testimony suggests. Also, we find no basis for accepting SCE's nonsensical claim that it "consistently spent an average of $12 million per year…" (Exhibit 283, p. 6.)

**(2000 Dollars X 1000, 100% Level)**

| | FERC Account 517 | FERC Account 532 | Total Site Projects |
|---|---|---|---|
| Labor | 280 | 12 | 292 |
| Non-Labor | 5,666 | 3,235 | 8,901 |
| Totals | 5,946 | 3,247 | 9,193 |

Sources: Exhibit 7, pp. 80, 82; Exhibit 136, pp. 38-40. The non-labor forecast for Account 517 reflects the $4.378 million Y2K adjustment for 1998 calculated by ORA.

#### 3.1.2.7. Workers' Compensation Adjustment

SCE's Master Insurance Program (MIP) provided workers' compensation to contractors prior to 1999. Since October 1999, SCE has required all contractors to carry their own insurance coverage. SCE states that it must cover all future claims for contractors covered under the original MIP. To provide funding to cover claims for contractors' work prior to October 1999, SCE's forecast for the Nuclear Support/FERC Account 528 pairing includes SONGS-related MIP costs of $1.710 million for the test year. The three-year averaging method used by SCE for this function includes MIP claim funding of $920 thousand. SCE's Adjustment #40 adds $790 thousand to the test year forecast to yield the total MIP cost of $1.710 million.

TURN objects to the inclusion of the $1.710 million for MIP claim costs in the O&M forecast. TURN takes the position that the cost of pre-1999 claims should not be borne by current ratepayers beginning in 2004. TURN believes that claims made prior to the beginning of the ICIP period should be extinguished as generation-related regulatory assets that cannot be collected after the end of 2001, while the cost of claims begun during the ICIP period should be assumed to have been covered in full by ICIP prices. If the MIP costs are allowed, TURN believes that it is questionable whether a constant amount should be allowed each year, and that in any event the amount allowed should not be subject to escalation.

***Discussion***

SCE has shown that these workers' compensation costs are appropriately charged to ratepayers. The ICIP proposal adopted by D.96-04-059 included a provision (Section 4.8.5) by which SCE could request recovery of certain expenses separately from the ICIP price, including worker and third party claims. The evidence does not support a finding that ICIP prices included all claims begun during the ICIP period. With respect to earlier claims, we find no basis for characterizing them as stranded costs. TURN's proposal to disallow the costs therefore will not be approved. With respect to TURN's secondary proposals, the amount requested is based on historical costs and is therefore reasonable, and no cause has been shown to exclude the costs from escalation.

#### 3.1.2.8. Labor Scarcity Adjustment

According to SCE, the nuclear industry is facing a labor shortage for certain categories of "nuclear trained" personnel.[12] SCE has determined that while the demand for nuclear trained and qualified personnel is likely to remain fairly stable, the supply of such personnel has decreased and will continue to do so. SCE bases this determination on recent nuclear industry reports and its own analysis of SONGS 2 & 3 demographic and regional demographic data.

Industry-wide, the nuclear workforce is aging and there has been a decline in the number of college students interested in nuclear careers. Certain craft positions are also in short supply due in part to fewer departures from the U.S. Navy. According to SCE, a nuclear industry trend to shorter outages means that

[12] "Nuclear trained" personnel are those in the nuclear power workforce with training in fields related to nuclear technology, including nuclear engineers and technicians with formal education or vocational training from educational institutions, and individuals with training in nuclear fields from the U.S. Navy.

craft workers needed for outages cannot obtain enough work to make a living, and the resulting workforce attrition has led to a situation where remaining workers are able to successfully request higher wages.

SCE finds that the industry-wide challenge of ensuring an adequate number of workers to operate nuclear power plants is particularly acute at SONGS 2 & 3 for several reasons. These include the high cost of living in Southern California, limited career opportunities due to the fact that SONGS is the only nuclear station operated by SCE, SCE's financial challenges, California's chaotic energy market, and California's law against future nuclear development. The average age of the SONGS nuclear workforce is 48, and SCE expects this will result in substantial retirements of qualified workers in the coming years. By 2004, 14% of the SONGS workforce will be of retirement age.

To address the labor scarcity challenge, SCE has developed a strategy that includes a job skills program aimed at high school students interested in technician jobs, a career program for high school students interested in professional jobs, a summer hire and intern program, signing bonuses based on 10% of base pay, referral bonuses, a relocation allowance with reimbursements of $34,000 for homeowner, supplemental relocation allowances, and training. SCE expects to incur added costs of nearly $4 million in 2002 and again in 2003 to recruit and train key talent during this anticipated labor shortage.

According to SCE, these added costs were not included in the historical period (1996-2000) costs because the impending labor shortage had not yet occurred during those years. As shown in the Joint Comparison Exhibit, SCE's Adjustment #41 adds $3.937 million to the test year 2003 O&M forecast to account for these anticipated costs.

ORA finds that SCE did not adequately support Adjustment #41. ORA proposes rejection of the adjustment on several grounds, including the following:

- A Nuclear Energy Institute (NEI) report prepared by Navigant Consulting projects a shortage of nuclear engineers as narrowly defined, but ORA found that SCE's labor scarcity testimony combined all engineers who work in the nuclear industry as nuclear engineers.
- According to ORA, a 1999 study of SONGS staffing commissioned by SCE and conducted by Martin & Associates found that SONGS is staffed 53% to 117% above the industry median.
- An October 2000 NRC study of labor market trends for nuclear engineers noted that the scarcity of nuclear engineering graduates was based on the assumption of a strong U.S. economy.
- Documentation that SCE submitted support of the adjustment does not justify a scarcity of critical positions, according to ORA. For example, SCE did not show past experience indicating a need for hiring incentives in relevant positions, and SCE admitted to ORA that there had not been any failed recruitment efforts. Also, SCE did not provide specific data on new hires based on attrition and vacancies, and it did not provide job description and classification data. ORA found that SCE used broad definitions for critical positions for which the scarcity adjustment is sought.
- SCE did not substantiate to ORA the actual training requirements for anticipated new hires.
- SCE did not explain to ORA's satisfaction why historical expenditures for training and certification are inadequate to meet the training and certification requirements for anticipated new hires.
- ORA noted that SCE's plans for the 2002 summer hire program had not been developed and implemented, and historical data and analysis on the summer hire program was not available.
- ORA noted that SCE did not address the current state of the economy and how it might impact the adjustment.

***Discussion***

While SCE has demonstrated that the labor market for certain nuclear job categories is expected to remain tight during the test period, it has not translated the existence of this challenge into a demonstrated need for an adjustment of nearly $4 million. ORA's analysis, summarized above, casts considerable doubt on the reasonableness of SCE's justification for the adjustment. Particularly troubling is a lack of substantiation by SCE for the amounts requested for the summer and training programs that represent a substantial portion of proposed Adjustment #41.

SCE had difficulty filling technician positions in 2001 and 2002, and since mid-2002 it has only been able to hire nuclear trained engineers with signing bonuses and relocation allowances. This corroborates the need for the company to incur scarcity related expenses at some level. SCE stated in its rebuttal testimony that it recorded approximately $1 million in additional costs in 2002 to attract, hire, and train qualified replacements for nuclear trained personnel. This demonstrates that SCE's direct evidentiary showing, in which it projected expenses of $3.85 million for 2002, has not been adequately substantiated. We find that it justifies a labor scarcity adjustment of $1 million in lieu of the requested adjustment of $3.937 million that is set forth in Exhibit 403. We will apply the $1 million adjustment to the various FERC accounts in the same proportions as set forth in Exhibit 403, pp. 97-108.

#### 3.1.2.9. Plant Security Adjustment

SCE made a future year adjustment of $5.650 million (Adjustment #45) to reflect increased security costs at SONGS 2 & 3. SCE upgraded its security programs as a result of the terrorist attacks of September 11, 2001 and subsequent NRC directives. Among other things, the NRC required nuclear power plants to increase patrols, augment security forces, and heighten coordination with law enforcement and military authorities. In response, SCE established new security posts that must be covered 24 hours per day, seven days a week. Adjustment #45 captures the increased security costs by increasing the 2001 estimate to reflect an increase in overtime costs for the initial posts that were added, and increasing the 2002-2003 estimates to reflect the increased number of security guards that SCE plans to hire.[13]

ORA recommends rejection of Adjustment #45 on several grounds. ORA believes that it is premature to accept SCE's increased number of security guards because cost-sharing arrangements at the state and federal levels have not been determined. Also, ORA believes that national security matters fall largely under the jurisdiction of the federal government, and that California ratepayers should not be exclusively obligated to bear the burden of this type of expense. Further, since SCE has not previously raised the issue of any inability of SONGS security personnel to deter vehicular intrusion, ORA assumes that historical/recorded costs are adequate to allow SCE to meet this type of threat.

***Discussion***

The evidence shows that as a result of the September 11 terrorist attacks and subsequent NRC directives, added security costs have been created for SONGS 2 & 3 in 2003 that did not exist during the 1996-2000 historical period. It also shows that the SONGS 2 & 3 co-owners are at present solely responsible for these increased costs. SCE cannot rely on the presence of U.S. Marines near SONGS 2 & 3 to avoid increased security costs. Moreover, ORA has not shown that it is reasonable to wait until Congress and the NRC fully evaluate security

[13] As of January 2003, SCE had hired 62 security guards to meet the increased requirements established by the NRC.

requirements, and implement new statutes and regulations that might reduce SCE's security cost responsibility, before providing ratepayer funding for increased security at SONGS 2 & 3. Adjustment #45 is a reasonable means of recognizing added security costs that SCE must incur, and it will therefore be adopted.

#### 3.1.2.10. Maintenance/FERC Account 524

SCE records expenses for training, certification, qualification, safety classes, and employee recognition awards for Maintenance Division personnel in the Maintenance/FERC Account 524 pairing. SCE used the last recorded year to forecast labor costs and a five-year average to forecast non-labor costs. SCE forecasts a total of $3.494 million in O&M expenses for this pairing, which represents an increase of 12% above year 2000 expenditures.

SCE used the last recorded year for labor costs because it includes the "final effects" of certain "programmatic changes" for maintenance personnel training and certification requirements. SCE implemented these programmatic changes during the 1998-2000 period in accordance with Institute of Nuclear Power Operations (INPO) Academy Documents that raised industry standards for craft and direct supervisory qualifications.

Since the programmatic changes were reflected in 1998-2000 period, ORA believes that it is appropriate to use a three-year average (1998-2000) for the labor forecast for the Maintenance/FERC Account 524 pairing. This results in a forecast of $2.604 million, or $890,000 less than SCE's forecast.[14] ORA rejects SCE's justification for using the last recorded year as unsubstantiated.

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[14] As shown in Exhibit 283, p. 22, SCE determined that due to a calculation error in ORA's forecast, the $890,000 difference should be $680,000. The Joint Comparison

*Footnote continued on next page*

***Discussion***

SCE relies on the assertion that the year-2000 recorded expenses reflect the final effects of a new program. SCE implies that the expenses for 1998 and 1999 were so low that including them in a three-year average would distort the forecast. If that were the case, it should not have been difficult for SCE to show what the actual costs were in each of the three years. We find that SCE's "final effects" argument is inadequate to justify use of the last recorded year. ORA's proposal to use a three-year average for labor costs is therefore adopted.

#### 3.1.2.11. Maintenance/FERC Accounts 530, 531, and 532

For the Maintenance/FERC Accounts 530, 531, and 532 functional group pairings, SCE used five-year averages to develop its forecasts. SCE notes that the labor costs recorded in Accounts 530 and 531 showed gradual declines during the 1996-2000 period, while the amount recorded in Account 532 showed an increase. This is due to a change in how maintenance support activities are reported. Costs formerly recorded against the direct maintenance activity account are now recorded in Account 532. SCE notes that in the aggregate, the labor cost in the three accounts was relatively constant.

ORA used the last recorded year (2000) for Accounts 530 and 531, for which there was a declining trend in labor costs. ORA used a five-year average for Account 532, for which there was an increasing trend. This method, along with ORA's recommendations with respect to adjustments, results in lower ORA

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Exhibit shows SCE's forecast as $3.022 million, ORA's as $2.604 million, and the difference as $418,000. (Exhibit 403, p. 111.)

forecasts for Account 530 ($6.954 million, or $818,000 less than SCE's forecast of $7.772 million) and Account 531 ($8.179 million, or $1.248 million less than SCE's forecast of $9.427 million).[15] ORA acknowledges SCE's explanation that the aggregate labor costs in all three accounts were relatively stable from 1996 to 2000. However, ORA does not accept this explanation as justification for SCE's decision not to use the last recorded year for Accounts 530 and 532. ORA believes that the year 2000 recorded costs incorporate the shift from direct maintenance accounts to Account 532.

***Discussion***

SCE has shown that Maintenance/FERC Accounts 530, 531, and 532 are linked because of how activities were reported, and that a consistent methodology should be used for the labor component of all three accounts. Thus, at a minimum, ORA should have used the last recorded year for Account 532 since it did so for Accounts 530 and 531. SCE has also shown that five-year averaging is appropriate because of the cyclical nature of the underlying activities and related expenditures. SCE's five-year averaging forecast method for these functional group/FERC account pairings will therefore be adopted.

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[15] Exhibit 283, p. 22, shows that the difference between SCE's and ORA's forecasts for Maintenance/FERC Account 530 should be $964,000. The Joint Comparison Exhibit shows that for Account 530, SCE forecasts expenses of $7.613 million and ORA forecasts expenses of $7.036 million, a difference of $577,000; and that for Account 531 SCE forecasts $9.412 million and ORA forecasts $8.179 million, a difference of $1.233 million. (Exhibit 403, pp. 112-113.)

#### 3.1.2.12. Nuclear Support/FERC Account 524

SCE forecasts expenses of $19.219 million for this functional group / FERC account paring. Between 1996 and 1997 there was a significant labor cost decrease that was almost fully offset by an increase in non-labor costs. SCE explains that this was mainly due to a 1996 reversal of estimated severance costs as a credit to non-labor and recording of the actual cost to labor. To exclude the effects of this transaction, SCE selected a four-year average for both labor and non-labor costs for the Nuclear Support / FERC Account 524 pairing. SCE notes that the work scope and cost for this pairing remained relatively constant over the period 1997-2000.

ORA follows the basic framework of SCE's analysis but believes that both 1996 and 1997 recorded data should be excluded for the same reason that SCE excluded 1996. ORA therefore used a three-year average (1998-2000) for the labor and non-labor estimate for Nuclear Support FERC Account 524. ORA's forecast is $18.35 million, or $869,000 less than SCE's forecast.[16]

***Discussion***

ORA states that the impact of severance costs for both 1996 and 1997 were omitted because "these two years are not reflective of costs associated with this account." (Exhibit 113, p. 7-B-56.) However, the evidence (Exhibits 8 and 283) shows that the severance transaction affected 1995 and 1996 only. No good cause has been shown for excluding 1997. SCE's four-year averaging method will therefore be adopted.

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[16] Exhibit 283 shows that correction of an ORA calculation error revises the $869,000 difference to $934,000. The Joint Comparison Exhibit shows SCE's forecast as $20.134 million, ORA's as $19.809 million, and the difference as $325,000. (Exhibit 403, p. 115.)

### 3.1.2.13. Nuclear Support/FERC Account 528

SCE forecasts expenses of $2.295 million for this functional group/FERC account pairing, in which SCE records costs for miscellaneous corporate adjustments that relate to SONGS functions. The corporate adjustments may include settlement costs due to bankruptcies, fines, and other litigation. SCE's forecast, based on a three-year average, excludes 1996 and 1997 because those years reflected one-time offsetting adjustments. SCE expects the costs for the most recent three years to continue in the future. SCE states the forecast includes the MIP workers' compensation adjustment, discussed above, as well as $555,000 for the return of rebuilt plant equipment to inventory and $277,000 for miscellaneous other costs. These include normalized paid time-off expenditures associated with SONGS employees.

ORA does not believe that SCE provided sufficient information to evaluate this functional group/FERC account pairing, and recommends removal from the O&M forecast all amounts except $1.71 million in MIP costs. This results in a proposed disallowance of $585,000.

***Discussion***

SCE's forecast for this pairing includes MIP workers' compensation costs, the return of inventory, and normalized paid time-off expenditures. While the amounts and purposes of expenditures in this pairing have varied considerably over the five-year recorded period, we find no basis for assuming that no expenses excepting the MIP costs will occur in the test year. SCE's use of a three-year average of recorded/adjusted data is reasonable and will be adopted.

### 3.1.2.14. Nuclear Support/FERC Account 532

For Nuclear Support/FERC Account 532, in which SCE records costs incurred by the Material Support section, SCE used the last recorded year for labor and a three-year average (1998-2000) for non-labor. SCE forecasts O&M costs of $4.559 million.

This pairing includes debits and credits for obsolete and salvaged inventory and credits from the sale of this material. It also includes costs for all services performed for SONGS by SCE's Procurement And Material Management division (PAMM). PAMM activities include procurement, expediting, contract administration, and support of the Material Management System. SCE states that PAMM costs charged to this account increased in 1998 due to corporate accounting changes, and it therefore used a three-year average to exclude pre-1998 costs.

Finding SCE's explanation of the 1998 accounting change insufficient, ORA proposes a five-year average to forecast the non-labor forecast for this pairing. ORA accepts SCE's forecast for labor. ORA's forecast is $4.052 million, or $507,000 less than SCE's forecast.[17]

***Discussion***

SCE has not shown that the 1998 accounting change justifies its use of a three-year average. Even if SCE headquarters began charging SONGS more for corporate services in 1998, SCE's SONGS witness did not demonstrate a compensating reduction in headquarters costs. If SCE is going to rely upon a corporate-wide accounting change to justify a rate increase, it is incumbent upon SCE to demonstrate that real cost increases occurred, not merely that one department is charging another department more for services provided. ORA's proposal to use a five-year average is therefore adopted.

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[17] The Joint Comparison Exhibit shows SCE's forecast as $4.451 million, ORA's as $4.052 million, and the difference as $399,000. (Exhibit 403, p. 116.)

#### 3.1.2.15. Other Methodological Issues

In its rebuttal testimony SCE identified four functional group/FERC account pairings for which methodological differences between SCE and ORA resulted in forecast difference of $250,000 or less. These pairings, and the amounts by which SCE's forecast exceeds ORA's forecast, are Operations/FERC Account 524 - $52,000, Maintenance FERC Account 528 – negative $214,000 (i.e., ORA exceeds SCE), Radchemical Control/FERC Account 523 - $64,000, and Nuclear Support FERC Account 529 - $184,000. The net difference for these four pairings is $86,000.

***Discussion***

For both Operations/FERC Account 524 and Nuclear Support/FERC Account 529, SCE used five-year averages. ORA used last recorded year and four-year averages, respectively. We find that five-year averages are likely to be more reliable for these pairings. For Maintenance/FERC Account 528, SCE used the last recorded year. SCE has justified such use by showing that (1) for labor, it gained efficiencies through programmatic enhancements and (2) for non-labor, only the year 2000 fully reflects cost reductions associated with inventory reductions. For the Radchemical Control/FERC Account 523 pairing, SCE used the last recorded year for both labor and non-labor. SCE has shown that this is necessary to reflect cost shifts from Account 520. For the foregoing reasons, we will adopt SCE's forecasts for these four pairings.

#### 3.1.2.16. Removal of Outage Expenses

Consistent with its proposal for recovery of expenses for refueling and maintenance outages (see Section 3.1.3 below), SCE intended to remove all outage-related costs from its base recorded costs for 1996-2000. This included costs related to Cycles 9, 10, and 11 outages. However, upon review of several FERC accounts, ORA found that not all such costs had been removed by SCE.

ORA recommends removal of these additional outage-related amounts from the base O&M forecast. As set forth in Exhibit 283, Appendix B, as well as Exhibit 403, pp. 125-142, ORA's proposal to remove the outage-related amounts as recommended by ORA affects 17 functional group/FERC account pairings for a total proposed disallowance of $2.557 million.

In its rebuttal testimony, SCE states that the amounts identified by ORA may be removed from the base O&M forecast. However, SCE asserts that the identical amount of costs should be added to the refueling and maintenance outage cost recovery mechanism.

***Discussion***

ORA has identified refueling and maintenance outage-related expenses that SCE included in its base O&M forecast for SONGS 2 & 3, even though SCE proposes recovery of outage-related expenses separately and apart from the base revenue requirement. SCE's rebuttal testimony does not deny that the subject costs are outage related, and SCE's reply brief acknowledges that the company's "initial testimony incorrectly identified them in the wrong category." (SCE Reply Brief, p. 33.)

In order to remove all refueling and maintenance outage O&M costs from the base O&M forecast as intended by SCE, we will adopt ORA's proposal to remove a total of $2.557 million in outage costs from the affected functional group/FERC Account pairings underlying the base O&M forecast. SCE's proposal to add this amount to its outage-related cost recovery mechanism is addressed in Section 3.1.3.

#### 3.1.2.17. NRC Licensee Fees

The NRC assesses license holders two types of fees under the Omnibus Budget Reconciliation Act of 1990. License and inspection fees recover the NRC's costs of providing special benefits to identifiable applicants and licensees. Annual fees recover generic and other regulatory costs not otherwise recovered through license and inspection fees. SCE's Adjustment #36 reflected net fee increases in 2001 and 2002 and a decrease in 2003. This adjustment affects the Nuclear Support/FERC Account 517 pairing.

As set forth in the Federal Register of April 3, 2003, the NRC is amending its regulations to increase annual fees for fiscal year 2003. The updated annual fee for each power reactor is $3.278 million for a total of $6.556 million in 2003 dollars, or $6.138 million in 2000 dollars. This represents an increase of $852,600 (2000 dollars, 100% share) over the $5.286 million amount that SCE had previously forecast in this proceeding. In its May 2003 update testimony, SCE presented an updated base O&M forecast reflecting the revised NRC annual fees.

***Discussion***

No party took issue with SCE's Adjustment #36 or the May 2003 updated forecast of NRC fees. Since the expenses are attributable to readily identifiable government action and are readily quantifiable, they will be approved.

##### 3.1.2.18. Conclusion – SONGS 2 & 3 Base O&M

Incorporating the foregoing resolution of various O&M issues, the following table sets forth the adopted test year 2003 SONGS 2 & 3 base O&M forecast by FERC Account and functional group.

#### 3.1.3. SONGS 2 & 3 Outage O&M

##### 3.1.3.1. Cost Recovery Proposal

While there was some confusion among SCE and ORA witnesses regarding SCE's proposal for recovery of SONGS refueling and maintenance outage O&M costs, the record regarding the nature and intent of SCE's proposed mechanism is clear. SCE requests that a "flexible outage schedule mechanism" similar to that adopted and affirmed in SCE's last three general rate cases be established. SCE's proposed mechanism works in conjunction with its Post-Test Year Ratemaking (PTYR) proposal. A standard per unit per outage cost would be established in this GRC, and SCE would include with its PTYR filings a refueling and maintenance outage O&M forecast based on the number of outages forecast to occur in the next year. SCE requests that the Commission establish in this proceeding a forecast for its refueling and maintenance outage costs of $52.462 million (2000 dollars, 100% level) per outage per unit, plus the $2.557 million that was removed from the base O&M forecast.

ORA does not take issue with the $52.462 million outage cost, but it objects to SCE's proposal to add the $2.557 million in outage costs removed from the base O&M forecast. Aglet disputes the level of SCE's estimated outage cost.

***Discussion***

Since it is not possible within the context of a GRC to predict with reasonable reliability the number of refueling and maintenance outages that will occur at SONGS in any one of the future years of the GRC cycle, inclusion of outage-related expenses in the base O&M forecast could lead to an unreliable forecast. SCE's proposed mechanism uses more reliable annual forecasts of the number of outages in the following year. It will therefore be adopted, provided that this approval does not constitute full approval of SCE's PTYR proposal, which is further addressed in Section 11 of this decision. Sections 3.1.3.2 and 3.1.3.3 below address disputes affecting the amount of the outage cost to be adopted. Because, as discussed therein, we do not adopt any revisions to SCE's original forecast, we adopt a per unit per outage cost estimate of $52.462 million (2000 dollars, 100% level) The SCE share is $39.373 million.

#### 3.1.3.2. Reinstatement of Excluded Costs

Since we have removed $2.557 million in outage related O&M expenses (2000 dollars, 100% level) from the SONGS 2 & 3 base O&M forecast for 2003, SCE contends that the identical amount should be added to the refueling and maintenance outage cost estimate. As a result, SCE contends that the cost estimate should be $55.1 million per unit per outage instead of $52.5 million.

***Discussion***

SCE's evidentiary support for its proposal to reinstate the excluded outage costs on a dollar-for-dollar basis consists of the following quote from its rebuttal testimony:

> ORA's proposed disallowance of Refueling Outage (RFO) costs are (sic) based on outage related function numbers appearing in workpapers in historical years 1996-2000. These costs may be removed from the historical recorded period, and thus the Base O&M Test Year estimate, but must be added to the RFO cost estimate. Therefore, the RFO estimate must be increased by the $2,557K (2000$, 100% level) for each outage. (Exhibit 283, p. 21.)

Apart from SCE's insistence that the $2.557 million that it mistakenly included in its base O&M forecast simply must be added to its per unit per outage forecast, there is no evidence to support the proposal. Moreover, there appear to be conceptual problems with it.

First, we do not find that SCE has addressed the unit of measurement problem associated with removing annualized expenses from the base O&M forecast and adding them to the per unit per outage forecast at issue here. In addition, for purposes of estimating its per unit per outage cost, SCE relied on a budget-based approach (in the form of adjustments for numerous specific, major activities) combined with adjusted Cycle 11 costs. (Exhibit 8, p. 100.) SCE has not shown whether, or how, it reconciled the amounts removed from the base O&M forecast with the budget-based per outage cost estimate.

The record before us does not allow us to conclude that any amount should be added to SCE's per unit per outage forecast as a result of the correction to SCE's base O&M forecast error, let alone the precise amount that was removed from the base forecast. SCE's proposal to reinstate that amount is denied.

#### 3.1.3.3. Mobilization Adjustment

SCE developed its estimate of per unit per outage costs by including an adjustment of $3 million for SONGS Unit 3 Cycle 11 "permanent Unit 3 Mob/Experience Factor/Timing." Because the outage estimate uses an average of Unit 2 and Unit 3 costs, the effect of this adjustment is to add $1.5 million to the unit/outage cost forecast. Aglet recommends the removal of this adjustment.

***Discussion***

SCE's witness testified that this adjustment reflects the need for SCE to mobilize its outage forces. In past years, outages at the SONGS units occurred back to back, and outage workforce mobilization was only required once. Due to a fire and forced outage in Unit 3 in 2001, the outages are now nine months apart, and mobilization costs are incurred for each outage. SCE has justified this adjustment, and Aglet's proposed reversal of it is therefore denied.

### 3.1.4. SONGS 1 Shutdown O&M

SONGS Unit 1 was permanently shut down in November 1992 and placed in a SAFSTOR (safe long-term protective storage prior to dismantling) configuration in 1993. Decommissioning and dismantling of SONGS Unit 1 began in June 1999.

D.92-08-036 provided that rate recovery of SONGS 1 shutdown O&M expenses would be addressed in SCE's GRC's until SONGS 1 is decommissioned.

Pursuant to D.97-08-056 and D.99-06-007, SONGS 1 O&M expenses are recovered through SCE's Nuclear Decommissioning Charge until used fuel is removed from the SONGS 1 used fuel pool and placed in dry storage. SCE anticipates this will occur prior to 2005. The scope of SONGS 1 shutdown O&M expenses is limited to assuring safe storage of used fuel until it is removed, and preservation of safe physical conditions in the areas of SONGS 1 not under the control of the decommissioning project. When all of the SONGS 1 used fuel is removed from the SONGS 1 used fuel pool, and the used fuel pool is ready for transition to decommissioning, SCE will make an advice letter filing to (1) remove the variable SONGS 1 shutdown O&M expenses from rates and (2) to reallocate the fixed SONGS common costs to SONGS 2 & 3 O&M and capital as well as the SONGS 1 decommissioning project.

SCE estimates direct shutdown O&M expenses of $3.864 million (2000 dollars, 100% share) for 2003. In addition, SCE estimates the allocation of SONGS common costs to SONGS Unit 1 shutdown O&M as $3.310 million (2000 dollars, 100% share). ORA reviewed SCE's account specific estimates for SONGS Unit 1 shutdown O&M expenses. ORA recommends no changes to, and therefore stipulates to, the estimates.

***Discussion***

SCE's estimate for direct shutdown O&M expenses is approximately one-half the level adopted in the 1995 GRC. This is consistent with SCE's testimony that certain functions required for the long-term storage of the plant are now complete, reducing the need for future use of contract labor. We find SCE's estimates of direct shutdown O&M and of allocated common costs to be reasonable, and therefore adopt them.

#### 3.1.5. SDG&E's Share of SONGS Costs

SDG&E owns a 20% share of the SONGS units. To ensure consistent treatment of SONGS expenditures and to avoid duplicate litigation, the Commission has addressed SONGS-related expenses that SCE bills to SDG&E in SCE's GRCs. In this proceeding, SDG&E requests that the Commission:

- Approve SCE's forecasted SONGS costs as set forth in A.02-05-004.
- Approve $15.806 million as SDG&E's share of SONGS 2 & 3 capital additions for 2004 and authorize SDG&E to reflect this approved amount in calculating the depreciation expense and other costs associated with these capital additions in its Test Year 2004 cost of service proceeding (A.02-12-027 / A.02-12-028).
- Approve $67.585 million as SDG&E's share of SONGS 2 & 3 O&M expenses for 2004 (other than refueling outage expenses) and authorize SDG&E to reflect this revenue requirement in rates effective January 1, 2004.
- Approve $12.468 million as SDG&E's share of each SONGS 2 & 3 refueling outage that occurs in 2004 and 2005 and authorize SDG&E to file annual advice letters on November 1, 2003 and November 1, 2004 to specify the number of SONGS refueling outages expected to occur during the following year and the escalated cost per outage.
- Approve $2.635 million as SDG&E's share of SONGS 1 shutdown O&M expenses for 2004 and authorize SDG&E to reflect this revenue requirement in rates effective January 1, 2004.

***Discussion***

Except for SDG&E's request that we approve SCE's SONGS-related proposals in full, no party takes issue with the framework of SDG&E's proposals, as set forth above and explained in its direct testimony (Exhibit 261) and update testimony (Exhibit 414). We find the framework to be reasonable and consistent with our prior decisions for addressing SDG&E's SONGS costs in SCE's GRCs. For the most part, SDG&E's proposals consist of determining its costs by applying the 20% ownership share to SCE's costs.

However, the specific dollar amounts for which SDG&E seeks approval are calculated with the assumption of our full approval of SCE's requests for SONGS. Since SDG&E's costs for SONGS are predicated upon its 20% ownership share, the amounts requested by SDG&E must be adjusted to reflect the corresponding 100% level of capital and O&M costs for SONGS 2 & 3 as well as the amortization period adopted in this decision. We will approve SDG&E's requests as set forth above, subject to the adjustments required to reflect SONGS-related determinations made in this decision.

## 3.2. Palo Verde Nuclear Generating Station

SCE owns a 15.8% share of Palo Verde Nuclear Generating Station Units 1, 2, and 3 (Palo Verde), which are located 50 miles west of Phoenix Arizona. Arizona Public Service (APS) is operating agent of Palo Verde, the nation's largest nuclear installation. SCE implements its ownership responsibilities through participation in Administrative, Engineering and Operations, and Audits Committees.

Since 1997, SCE has recovered its share of Palo Verde operating costs through a balancing account ratemaking mechanism adopted D.96-12-083. Pursuant to D.01-09-041, this mechanism will continue until the effective date of a decision on this GRC, at which time the adopted 2003 capital and O&M forecasts for Palo Verde will be implemented.

### 3.2.1. Palo Verde Capital Expenditures

SCE forecast the capital budget for Palo Verde work on a project-by-project basis. SCE forecasts capital expenditures of $19.4 million in 2003 (nominal dollars, SCE share). ORA used a five-year average of nominal historical expenditures of $8.2 million, plus the $9.4 million cost of Unit 2 installation of steam generators, to arrive at a forecast of $17.6 million.

SCE contends that ORA's use of averaging plus extraordinary items is wrong because that method assumes that capital additions will be basically the same from year to year and that fixed rules exist for determining what type or size of projects are extraordinary. SCE also contends that ORA's averaging methodology was applied incorrectly because ORA used nominal dollars to calculate the five-year average. SCE determined that using common year dollars instead of nominal dollars would change ORA's adjusted 2003 estimate from $17.6 million to $19.07 million.

***Discussion***

We concur with SCE that the most accurate method for estimating an average of numbers from different years is to escalate them all into common year dollars. We note that when this adjustment is made to ORA's forecast, the resulting estimate is similar to SCE's. While we do not necessarily accept SCE's criticisms of the use of averaging for forecasting capital expenditures generally,[18] we find that SCE's project-specific forecast of capital expenditures for Palo Verde is reasonable and should be approved.

#### 3.2.2. Palo Verde O&M Expenses

SCE initially forecast Palo Verde O&M expenses of $42.6 million (2000 dollars, SCE share) based upon three-year averages for all FERC accounts except Account 517, which contains substantial SCE labor costs. SCE rejected averages for longer periods because Palo Verde operations were stabilizing in 1996 and 1997 after a period of elevated costs. SCE used a budget-based approach for

[18] See Section 3.1.1.2 of this decision.

Account 517, in which SCE's Palo Verde oversight labor costs are recorded. SCE estimated $42.3 million in base O&M expenses and $300,000 in oversight costs.

Due to declining Palo Verde O&M costs and what it believed to be inadequate justification for an increase above year-2000 costs, ORA recommended use of the last recorded year method for all Palo Verde estimates. The resulting ORA forecast of $41.2 million was $ 1.4 million less than SCE's forecast of $42.6 million.

TURN recommended a reduction to SCE's forecast of $3.267 million based upon updated APS budget data. SCE agrees that the approved budget for APS is an appropriate forecast, and it accepts TURN's recommendation provided that NRC annual fees are properly accounted for by booking fees that are in FERC Account 928 in APS' budget in SCE's Account 517. TURN stipulated to this accounting and revised its recommended reduction to $1.744 million. SCE calculated and supported a revised forecast of $39.517 million based upon the updated APS budget data and the accounting change.

***Discussion***

As shown in Exhibit 3, p. 15, Palo Verde O&M costs declined consistently throughout the recorded period, from $45.6 million to $41.2 million in 2000. The budget-based forecast of $39.517 million in Exhibit 327, which reflects the most recent budget information available, shows continued declines in Palo Verde O&M expenses that are not reflected in historical costs. We will adopt this budget based forecast as the most reasonable estimate of Palo Verde O&M expenses. SCE has justified its request for $300,000 for Palo Verde oversight activities, and ORA's proposal to reduce the oversight cost to $66,000 is denied. Similarly, we find no basis to reduce the estimate to exclude certain new plant security costs, as recommended by ORA.

### 3.3. Mohave Generating Station

SCE is the operating agent and owns 56% of Mohave Generating Station Units 1 and 2 (Mohave), located at Laughlin, Nevada. The Mohave Operating Agreement provides for its operation only through 2005. Other contracts, including those for the supply and transportation of coal fuel from the mine to the plant, also only provide for operation through 2005. While the future of the Mohave facility is in question (*see* A.02-05-046), it will operate through 2005.

SCE had expected to divest its share of Mohave until enactment of Assembly Bill (AB) X1-6 on January 18, 2001. Earlier, on May 10, 2000, it entered into an asset sale with AES with anticipated ownership transfer during the last half of 2000 or the first quarter of 2001.

#### 3.3.1. Mohave Capital Expenditures

SCE requests recovery of Mohave capital expenditures of $7.475 million in 2002 and $10.412 million in 2003, or a total for the two years of $17.887 million (all figures in nominal dollars, SCE share). SCE states that this level of investment is necessary to maintain reliable operations through 2005, and that it includes work necessary to ensure employee safety and environmental protection. According to SCE, no investment to extend operations beyond 2005 is included in its estimate of capital spending.

SCE stated that its capital spending at Mohave would yield O&M savings, but ORA found that the capital expenditures for 2002 would result in zero O&M savings and that its 2003 request would result in just $40,000 in O&M savings. Moreover, ORA found even those savings to be unsubstantiated. ORA also questions the reasonableness of SCE's capital spending given the likelihood of a shutdown of Mohave.

In arriving at its recommended capital expenditures, ORA considered only those projects earmarked by SCE as regulatory, safety, and environmental. These totaled $514,000 for 2002 and $1.180 million for 2003. Adding estimated blanket work order expenditures of $383,590 for each of the years 2002 and 2003, ORA arrived at estimated expenditures of $897,590 for 2002 and $1.564 million for 2003. ORA's recommended expenditures represent disallowances of $6.577 million for 2002 and $8.848 million for 2003, or a total of $15.425 million.

TURN took issue with a single capital project underlying SCE's capital forecast for Mohave—replacement of Cooling Tower 1EE. TURN recommends a permanent disallowance of the $1.23 million capital expenditure associated with the project.

***Discussion***

To explain its position on Mohave capital spending, ORA uses the analogy of a 15-year old car that has had hard service. ORA posits that its owner will think differently about repairs and maintenance than will the owner of a newer car. ORA also posits that, for safety reasons, the older car owner must maintain the brakes and tires as long as she operates the car, even if she plans to sell it within one week. Except for safety considerations, ORA assumes that further repairs are problematic, and that a convincing reason is needed to make them.

Like the oil change analogy that SCE used attempting to explain deferred spending at SONGS (*see* Section 3.1.2.3), we find ORA's vehicular maintenance analogy less than fully supportive of the associated recommendation. For one thing, we do not understand that SCE can easily sell or junk Mohave if needed repairs are too expensive, as the owner of a clunker vehicle might do. Also, we assume that the car in this analogy is required for transportation, and that reliability is important to the owner despite the vehicle's age. In fact, reliability issues may weigh heavily on the owner's mind precisely because the car is so old. A prudent owner who is in a position of having to operate the car for at least two more years will not necessarily limit expenditures to tires, brakes, and other safety components, but will instead perform all repairs and maintenance necessary to assure reliable automotive performance for those two years. An experienced automobile mechanic might advise the owner to install new spark plugs even though that might not improve safety. A prudent owner would heed that advice even though the mechanic did not determine through rigorous statistical analysis the probability that the old spark plugs would fail within two years. It almost certainly would not make sense for the vehicle's owner to plan on operating the vehicle on seven cylinders during its final years.

ORA's capital spending recommendation for Mohave reflects the concern that SCE will be spending substantial sums at ratepayer expense on projects for a generation facility that could be shut down in the relatively near future. This concern is not unreasonable, but the evidence does not support ORA's conclusion that SCE's planned capital spending should be limited to the bare minimum needed for regulatory requirements, environmental protection and safety. SCE's testimony shows that most of its planned investments, such as those for steam turbine buckets (blades), boiler tubes, electrical cables, and other components whose failure could cause a shutdown, are important for reliable operations at Mohave through 2005.[19]

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[19] SCE's capital forecast for Mohave includes 54 separate projects totaling $22.795 million (SCE share). These consist of 34 direct replacements, 17 upgrades and

*Footnote continued on next page*

ORA proposes to cut SCE's capital spending plans at Mohave by 86%, from $17.887 million to $2.462 million. We are concerned that cutbacks as severe as these may unduly impact production reliability. Whether or not Mohave continues to operate after 2005, determination of which is beyond the scope of this GRC, we intend to authorize the capital funding that is necessary for continued safe, reliable, and environmentally responsible operation of the plant through 2005.

TURN's proposed disallowance of the Cooling Tower 1EE investment will not be adopted. Even though TURN has shown that SCE's economic analysis showing a benefit to cost ratio of 2.55 may be based on faulty assumptions, and that the direct economic benefits of the investment are at best questionable, SCE has shown that the project was needed for safety as well as reliability purposes.

One point in ORA's car repair analogy is valid—SCE must convince us that the reliability projects and other proposed expenditures are necessary. SCE's direct testimony (Exhibit 17) adequately fulfils this requirement. For the foregoing reasons, and because the level of SCE's planned capital spending is generally consistent with Mohave capital expenditures of the 1996-2000 period, as shown in Exhibit 3, Figure II-5, p. 21, we will approve SCE's proposed spending plan for ratemaking purposes.

#### 3.3.2. Mohave O&M Expenses

Recorded/adjusted Mohave O&M expenses were $37.057, $31.105, $32.502, $26.971, and $25.359 million (2000 dollars, SCE share) in the years 1996 through

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modifications, and three new additions. SCE's performance objective for two-thirds (36/54) of these projects is reliability. Other performance objectives are heat rate, environmental, cost, and safety.

2000, respectively. SCE states that while operations expenses were relatively flat during this period, maintenance spending was temporarily but significantly decreased in 1999 and 2000, due largely to the expected sale of Mohave. SCE states that with the cancellation of the sale, the reduced level of maintenance spending in 1999 and 2000 cannot be sustained. For example, while the Mohave sale was pending SCE did not fill various vacancies as they occurred. After reducing its Mohave workforce by 46 employees beginning in 2000, SCE is now in the process of filling 35 vacancies at Mohave. In addition, training programs that were suspended are being reestablished.

Another O&M cost reduction at Mohave was realized in 2000 due to an abbreviated planned outage program. This was made possible when SCE determined on the basis of equipment assessments that a turbine overhaul scheduled for that year could be deferred. In addition, SCE notes, California needed the energy in 2000, so Mohave was kept operating as much as feasible. Finally, SCE states that it had no incentive to spend large sums on the 2000 outage program to benefit the new owner. According to SCE, the conditions that led to reduced planned outage expenses in 2000 will not recur in the test period.

Having determined that maintenance expenses were abnormally low in 1999 and 2000, SCE based its maintenance O&M forecast on three-year averages (1996-1998) for most FERC accounts. For operations, SCE used three-year averages for the years 1998-2000 for most FERC accounts after determining that use of those years properly captures a change in how employees charge their time to various accounts. SCE points out that its resulting O&M expense forecast of $30.633 million is consistent with the adjusted average O&M expenses for years prior to 1999.

ORA proposes a Mohave O&M forecast of $24.661 million, or $5.972 million less than SCE's forecast.[20] ORA based its forecast on expenses for the years 1999 and 2000 for all but one FERC account. ORA did so for two reasons. First, ORA believed that using only the earlier years, as SCE did, would result in omission of savings achieved through SCE's "Condition-Based Maintenance" policy. Second, ORA believes that there are serious issues and uncertainties about Mohave's status after 2005. ORA determined that costs for 1999 and 2000 best represent the required O&M expenditures since that period may be reflective of a possible divestiture scenario.

For FERC Account 501.13, ORA used the last recorded year to forecast labor expenses to reflect reductions in fly ash management costs, and it supported additional reductions in that account to reflect reduced centrifuge overhaul costs. ORA also recommended adjustments totaling $345,000 for one-time occurrences that assertedly are not reflective of 2003 expenditures.

***Discussion***

SCE has presented evidence justifying the exclusion of 1999 and 2000 recorded expenses from its Mohave maintenance forecast. Due largely to the then-pending sale of Mohave, SCE spent less on maintenance than it would have in those years if it had not been planning to divest the plant. Such reduced expenses are not likely to recur in the test period. We note that SCE's total O&M forecast of $30.633 million for Mohave is less than the recorded/adjusted expenses for any of the three years from 1996 to 1998.

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[20] The Joint Comparison Exhibit shows that the SCE/ORA differences attributable to the selection of record years total to $4.725 million, differences regarding FERC Account 501.13 total to $669,000, and other adjustments total to $345,000. (Exhibit 403, pp. 191, 201, and 203-204.)

At the same time, we find that ORA's reasons for using only 1999 and 2000 lack merit. The Condition-Based Maintenance policy has been in place since 1992, and the associated savings are reflected in each of the years from 1996 to 1998. Also, ORA has not established that the circumstances underlying the period during which the Mohave sale was pending are more representative of the GRC test period circumstances than those of the earlier three years. The planned sale involved the immediate transfer of ownership to a known third party, whereas the test period circumstances involve future uncertainty regarding the plant's operation after 2005 combined with an obligation to continue reliable operations until then. We find no basis for concluding that the low-cost performance of 1999 and 2000 will be replicated in the test period.

Finally, SCE has shown that ORA's proposed adjustments for fly ash management, centrifuge overhauls, litigation settlement, and other costs are not warranted. We find that SCE's O&M forecast for Mohave is more reliable than ORA's forecast. SCE's forecast is therefore adopted.

### 3.4. Four Corners Generating Station

SCE owns 48% of Four Corners Generating Station Units 4 and 5 (Four Corners), located near Farmington New Mexico. APS is the operating agent for Four Corners.

#### 3.4.1. Four Corners Capital Expenditures

According to SCE, the capital spending pattern at Four Corners is heavily influenced by plant overhaul schedules. Historical expenditures vary considerably from year to year. Between 1996 and 2000, SCE's share of Four Corners capital expenditures ranged from a low of $446,000 in 1998 to a high of $6.215 million in 1996, and the five-year average expenditure was approximately $3.1 million. (Exhibit 3, p. 24.) SCE requests recovery of Four Corners capital expenditures of $9.173 million in 2002 and $4.462 million in 2003, or a total for the two years of $13.635 million (nominal dollars, SCE share).

Finding that the Four Corners capital expenditures yield negligible O&M savings, and confronting a lack of information regarding priorities and costs for each capital project, ORA believes that capital expenditures should be limited to a five-year average of historical costs plus projects that SCE identified as having safety, environmental, or regulatory objectives. Based upon this position, ORA recommends that SCE's capital expenditures be limited to $2.858 million in 2002 and $2.876 million in 2003, or a total of $5.734 million. The difference between SCE and ORA for the two years is $7.901 million.

***Discussion***

Over 82% of the capital expenditures planned for Four Corners are focused on production reliability. Planned expenditures include replacement of turbine blades, boiler tubes, steam condensers, tubular air preheaters, and other components that would cause a shutdown if they failed. In its direct testimony, SCE identified and described 48 separate capital projects with a total cost of $18.858 million (SCE share). Two projects alone, replacement (retubing) of the Unit 5 main steam condensor and replacement of the tubular air preheater, required more than $3.8 million to complete in 2002. In other words, the costs for just these two projects exceed ORA's entire capital forecast for 2002.

We conclude that a forecast based upon a five-year average is inappropriate for Four Corners. Because the greatest part of Four Corners' capital expenditures are for reliability, we are concerned that adoption of ORA's recommended level of expenditures could, if implemented by the operating agent, significantly impact production reliability at Four Corners. We will adopt SCE's project-specific forecast for Four Corners capital expenditures.

### 3.4.2. Four Corners O&M Expenses

Recorded / adjusted Four Corners O&M expenses were $25.727, $20.921, $19.691, $22.363, and $27.208 million (2000 dollars, SCE share) in the years 1996 through 2000 respectively. SCE explains that while expenses were relatively flat from 1997 to 1999, they were higher in 1996 and 2000 due to large overhaul outages. Using five-year averages for all FERC accounts to smooth out the effect of the outages, SCE forecast test year 2003 O&M expense of $23.182 million for Four Corners. SCE notes that the 1996-2000 recorded expenses used in its forecast are among the lowest recorded over the last 21 years of data examined (using constant 2000 dollars).

ORA accepted SCE's five-year averaging methodology for FERC operations Accounts 500.15 through 507.15, because their recorded expenditures were constant. ORA proposes that three-year averages (1997-1999) be used for FERC maintenance Accounts 510.015 through 514.015 because the year 2000 indicates substantial increases in maintenance costs as a result of a major overhaul. Since no major overhauls are planned for the test year, and the next one had been planned for 2006,[21] ORA concluded that the test year forecast should exclude such costs. ORA's method yields a forecast of $9.994 million for Four Corners O&M, which is $2.384 million less than SCE's forecast of $12.378 million for maintenance accounts.

***Discussion***

SCE complains that by excluding 1996 and 2000 from the average, ORA would not compensate SCE for major overhaul outages such as those

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[21] SCE stated in its rebuttal testimony that, in August 2002, it learned that APS was planning a major overhaul of Unit 4 in 2004.

experienced in 1996 and 2000. However, the purpose of this GRC is neither to compensate SCE for past expenses nor to compensate it for future expenses that it will not incur. The purpose is to determine the just and reasonable revenue requirement for the 2003 test year by developing a forecast of expenses that will actually be incurred during that year. Since major outage overhauls are not planned for Four Corners in 2003, it would not be reasonable to include the costs of such overhauls in the forecast. ORA's use of a three-year average appropriately excludes those costs.

SCE notes that two minor maintenance outages are planned for 2003, one of nine days for Unit 4 and the other of 14 days for Unit 5. The 1997-1999 recorded costs reflect outage duration of 12 days. According to SCE, ORA's forecast "will severely under-fund" the 2003 minor outages. (Exhibit 288, p. 18.) In the absence of more compelling explanatory evidence regarding this asserted "severe" under-funding, this contention lacks merit.

ORA's methodology for Four Corners maintenance accounts is reasonable and yields the better forecast. ORA's proposal to reduce SCE's Four Corners O&M forecast by $2.384 million is therefore adopted.

### 3.5. Hydroelectric Generation

SCE operates and maintains 36 hydroelectric (hydro) generating plants consisting of 79 generating units with an aggregate 1,156 MW of capacity. Some of the facilities have exceeded 100 years of age, and most were constructed at least 50 years ago. Initial plant service dates range from 1893 to 1999.

#### 3.5.1. Hydroelectric Capital Expenditures

Using project-specific analysis, SCE forecasts capital expenditures of $17.691 million in 2002 and $15.121 million in 2003 for its hydro system, a total of

$32.812 million. These forecasted amounts are somewhat lower than the 1996-1999 average annual level of expenditures of $19.670 million.

As with SCE's other generation forecasts, ORA found that in its opinion SCE failed to provide adequate project-specific information. ORA therefore recommends a four-year average of historical expenditures as the basis for the capital expenditures forecast. ORA's approach yields a forecast of $14.432 million for each of the years 2002 and 2003, or a two-year total of $28.864 million. This represents a forecast that is $3.948 million less than SCE's two-year forecast of $32.812 million.

***Discussion***

ORA does not take issue with any particular capital project that SCE plans to undertake. Instead, ORA faults the methodology used by SCE to develop its forecast. As we have indicated earlier, a project-specific forecast has the potential for being the most reliable basis upon which to forecast capital expenditures. On the other hand, because projects may not always be implemented as planned, it may be appropriate to use other forecast methodologies such as averaging. With respect to SCE's hydro facilities, we find that SCE's project-based forecast is consistent with a properly determined averaging approach, i.e., one that uses five instead of four years and that accounts for inflation.

SCE has shown that when these corrections are made to ORA's averaging-based forecast, the result is a reduction of $942,000 from SCE's project-based forecast for 2002 and an increase of $1.888 million from SCE's forecast for 2003. This confirms the reasonableness of SCE's original forecast for hydro capital, which we therefore adopt.

### 3.5.2. Hydroelectric O&M Expenses

SCE forecasts hydro O&M expenses of $27.771 million for 2003. This represents an increase of 12% above the average level of expenditures for the 1996-2000 recorded period ($24.789 million). SCE asserts that the hydro facilities' advancing age is the major factor underlying this increase. In addition, SCE plans to undertake certain maintenance initiatives, notably painting. SCE has not painted most of the powerhouses, flow lines, penstocks, and generation equipment for over 20 years (Exhibit 18, p. 20). Other planned activities that are driving O&M increases include penstock and flow line condition assessments, wicket gate maintenance, and buttress repairs at Florence Dam.

ORA recommends an O&M forecast of $25.661 million for SCE's hydro system, which represents a reduction of $2.110 million from SCE's forecast.

***Discussion***

SCE has shown the unquestionable importance of maintaining its hydro facilities by, among other things, maintaining protective coatings (painting), ensuring the safe condition of penstocks and flow lines, ensuring efficient and reliable operation of wicket gates that control the amount and distribution of water to the turbine, and ensuring the safety of Florence dam by repairing its buttresses because they are subject to spalling due to extreme freeze/thaw conditions. We have no doubt that SCE's failure to carry out these activities could jeopardize the safe and reliable operation of its hydro system.

However, with the exception of the Florence Dam buttress repairs, which were suspended in the 1990's while seismic retrofit work was anticipated, SCE has not adequately explained why these important activities have taken on the degree of added importance during the GRC test period reflected in its forecast. More to the point, SCE has not satisfactorily explained what events have occurred requiring the expenditure of an additional 12% each year to operate and maintain the hydro system. For example, SCE leaves us to wonder why it did not paint its hydro facilities for more than 20 years but must do so during the ratemaking test period.[22]

We would expect a system most of whose components are 50 to 100 years old to have relatively high maintenance costs. However, during the recorded period from 1996 to 2000 the system was already old. SCE has not explained to our satisfaction why its test period maintenance costs should be so much higher than those of the same system were when those components were 45 to 95 years old. The fact that SCE did not apply paint for 20 years suggests inappropriate deferred maintenance as a possible answer.

The questions about SCE's hydro O&M forecast cast significant doubt as to the forecast's reasonableness. With one exception, ORA's forecast gives appropriate weight to past spending and needed projects, and is more reasonable than SCE's. We note that where SCE proposes a 12% increase, ORA's forecast represents an increase of 3.5% above the historical level of 1996 to 2000. ORA's forecast is therefore adopted, provided, however, that we will add $845,000 to ORA's forecast to include costs for the Florence Dam buttress repairs.

### 3.6. Other Generation

SCE's Pebbly Beach Generating Station on Santa Catalina Island consists of six diesel generators that represent the principal power source for 1800 residential and 500 commercial customers. SCE forecasts test year O&M

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[22] SCE's rebuttal testimony regarding the difficulty of painting penstocks does not overcome our concerns, nor does its rebuttal testimony regarding maintenance painting at Big Creek.

expenses of $1.518 million. SCE forecasts capital expenditures of $2.5 million for a Selective Catalytic Reduction system to reduce emissions ($2.2 million in 2002 and $0.3 million in 2003), $0.8 million in 2002 to repair and upgrade the fuel pier, and $0.3 million in 2003 to cover other routine capital related work. ORA agrees with SCE's O&M estimate. In a data request response, SCE indicated that the cost of the fuel pier project is less than is stated in SCE's testimony. ORA therefore proposes to remove $445,000 from SCE's capital request.

***Discussion***

SCE agrees with ORA's proposed $445,000 adjustment for the fuel pier capital expenditures. Therefore, both SCE's O&M forecast and its capital forecast, as adjusted, are uncontested. We will adopt these forecasts for Other Generation.

### 3.7. Generation Capital Additions for 1997-1998

#### 3.7.1. Introduction

In response to Public Utilities Code Section 367,[23] an electric industry restructuring statute that addressed utility recovery of uneconomic generation costs, as well as D.97-09-048, in which the Commission provided for the implementation of Section 367, SCE filed A.99-04-024 to recover approximately $83 million in capital additions that it made to certain non-nuclear generation plant in 1997 and early 1998.[24] Earlier, by A.97-10-024, SCE had applied for

[23] All section references herein are to the Public Utilities Code unless otherwise noted. Section 367 was added by Assembly Bill (AB) 1890 (Stats. 1996, Ch. 854).

[24] Among other things, D.97-09-048 established reasonableness review criteria applicable to capital additions made in 1996 and 1997. Pursuant to D.98-03-054, this period was extended through March 1998 (the date of commencement of operations of

*Footnote continued on next page*

"Competition Transition Charge" (CTC) recovery of its generation-related capital additions for 1996.

Commission restructuring policy promulgated in D.95-12-063 and legislative direction embodied in AB 1890 contemplated the divestiture of certain utility generation assets as part of the transition to a more competitive electric services industry. However, the subsequent breakdown of the wholesale electricity market led to significant changes in the policy for divestiture. Among other things, the Legislature amended Section 377 in January 2001 to (1) require public utilities to retain electric generation facilities until January 1, 2006 and (2) require that the Commission ensure that these facilities remain dedicated to service for the benefit of California ratepayers.[25]

The amendment to Section 377 was adopted after the evidentiary record in A.99-04-024 was closed. By ruling dated September 7, 2001, the assigned ALJ in A.99-04-024 noted that parties in that proceeding had not had an opportunity to comment on any effects that this statutory amendment might have on the criteria for evaluating the application. The ALJ set aside submission of A.99-04-024 and provided parties an opportunity to file comments and reply comments on the effects of amended Section 377. SCE, ORA, and TURN filed comments, and TURN filed reply comments. Upon review, the ALJ determined that the record in A.99-04-024 remained incomplete with respect to capital additions made for the purpose of plant reliability and obsolescence.

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the Independent System Operator (ISO) and the Power Exchange (PX)) due to delays in the startup of the ISO.

[25] Section 377 was amended by ABX1-6 (Stats. 2001, Ch. 2 of the First Extraordinary Special Session).

A subsequent joint ruling issued by the ALJs assigned to A.99-04-024 and this GRC on September 9, 2002 stated the following:

> The record in A.99-04-024 is incomplete regarding the 1997-98 capital additions made for purposes of plant reliability and obsolescence purposes. A.99-04-024 assumed that these projects for retained hydroelectric and coal generation plants were only necessary to maintain plant through December 31, 2001, and the testimony and analysis focused on this date. However, the amending of Section 377 means that plant must be maintained until January 1, 2006. Accordingly, either A.99-04-024 could be reopened for the purpose of taking further testimony on this issue, or a more appropriate proceeding addressing the Edison's retained plant and associated capital additions could be used such as Edison's current general rate proceeding A.02-05-004. (*Administrative Law Judges' Ruling on Certain Capital Additions to Non-Nuclear Generating Plant*, p. 3.)

The ALJs assigned to A.99-04-024 and this proceeding jointly determined that this is the more appropriate proceeding to address the 1997 and 1998 reliability and obsolescence capital additions to SCE's coal and hydro facilities. Their September 9, 2002 ruling directed SCE to submit testimony on the reasonableness of those capital additions and how they support continued reliable operation of utility-retained generation through January 1, 2006. The ruling specified, by individual project, $32.479 million in reliability and obsolescence capital additions to be addressed in this GRC.[26] The ruling further

[26] This was later revised to $30.937 million, consisting of $16.223 million for additions to coal plants and $14.714 million for additions to hydro plants. These amounts are for gross additions, i.e., they include corporate overheads, and they reflect SCE's share of additions for jointly owned plants. (*See* letter from SCE to ALJ DeBerry dated September 18, 2002, confirming clarification to the ruling of September 9, 2002. *See also* Exhibit 71, pp. 10 and 11.)

provided that consideration of capital additions for environmental, regulatory and safety and for divested fossil plants would remain with A.99-04-024.[27]

SCE served its supplemental testimony regarding the 1997-98 capital additions on October 1, 2002; this was later identified as Exhibit 71. SCE's policy witness also addressed the capital additions in Exhibit 69, Section I. SCE maintains that all of the $30.937 million in projects identified in the September 9 ruling comply with the four review criteria established in D.97-09-048. SCE also maintains that Section 367 does not apply to the capital additions reviewed in this docket. Nevertheless, SCE contends that all of the projects at issue meet the Section 367 requirement that the capital additions must be necessary to maintain the facilities through 2001.

ORA and TURN submitted written testimony on the 1997-98 capital additions on December 6, 2002. ORA takes the position that reasonableness of a capital addition must be evaluated on the basis of facts and circumstances known when the utility made the decision to make the addition. ORA state that it remains committed to the project-specific disallowances that it recommended in A.99-04-024. With respect to the projects transferred to this proceeding, ORA proposes disallowances of $14.932 million and $12.463 million, respectively, to SCE's coal and hydro additions, or a total of $27.395 million of the $30.937 million sought by SCE. TURN submitted testimony proposing disallowances totaling $7.642 million for Mohave Unit 1 centrifuge replacements, and on brief it recommends additional disallowances for investments at SCE's coal plants.

[27] The ALJ's proposed decision in A.99-04-024 was issued on December 9, 2003.

SCE submitted rebuttal testimony addressing the testimony submitted by ORA and TURN.

#### 3.7.2. Evaluation Criteria

SCE witness Fielder introduced SCE's policy perspective on the 1997-98 capital additions as follows:

> The [September 9, 2002] ALJ Ruling appears to recognize that assessing the reasonableness of these capital additions through the lens of short-term payoff is no longer appropriate. Rather, the ruling understands the new reality of retaining utility generation at least through 2006, and potentially through the end of their planned operating lives. (Exhibit 69, p. 5.)
>
> Most of the capital investments in these plants were made to replace obsolete components, or for regulatory or safety related requirements. [Footnote omitted.] In some instances, where an economic analysis was necessary they were justified on a "remaining life" basis consistent with our obligation to serve at the time. With this in mind, we are satisfied with our testimony in the capital additions proceeding and have, for the most part, simply re-filed it in this GRC. (*Id.*)
>
> In our view, these investments are clearly reasonable and their performance during our recent energy crisis is the proof. While California's citizens faced repeated curtailments and outright blackouts, these plants operated very well and provided power at cost-based rates. While certain parties may quibble over subtle differences in assumed discount rates and net present value analysis, the real world evidence of these investments' reasonableness was their performance during a crisis. As a matter of fundamental fairness and common sense the Commission should find these capital additions to be reasonable. (*Id.*, pp. 5-6.)

ORA and TURN urge that the reasonableness review criteria established by D.97-09-048 be observed in this GRC proceeding. Both of these parties base their proposed disallowances on their contention that SCE has failed to demonstrate compliance with those criteria with respect to various projects.

***Discussion***

As a condition precedent to utility recovery of uneconomic costs associated with capital additions made to generating facilities that were in existence as of December 20, 1995, Section 367 required that such additions be necessary to maintain those facilities through December 31, 2001, and reasonable as determined by the Commission. For capital additions made in 1996 and 1997 (and in 1998 until the ISO and PX commenced operations), D.97-09-048 further provided that cost recovery would be based on the Commission's after-the-fact (*ex post facto*) reasonableness review of recorded expenditures. Among other things, the Commission established the following reasonableness review criteria:

> In their applications [for transition cost recovery], PG&E, SDG&E, and SCE shall demonstrate how their requests for recovery of capital addition costs meet the following criteria, among others: (1) consistency with recent capital budgets and expenditures for respective power plants, (2) the need for compliance with other regulatory requirements, (3) cost-effectiveness and (4) the impact of the capital addition on the unit's heat rate. PG&E, SDG&E, and SCE, and other interested parties may propose additional evaluation criteria for Commissions consideration. (D.97-09-048, Ordering Paragraph 3, 75 CPUC 2d 449.)

At issue now is whether the reasonableness of the generation capital additions that SCE made in 1997 and early 1998 should be evaluated according to the criteria used for other capital additions reviewed in this GRC, as SCE urges, or according to the criteria established in Section 367 and D.97-09-048, as ORA and TURN urge. If the higher standards urged by TURN and ORA are applicable, then shorter payback periods may apply for cost-effectiveness analyses of capital projects, and SCE must show that improvement of a generating unit's heat rate was not the purpose of the expenditure.

This issue harkens back to the recent past, when the unambiguous policy of this state was promotion of a competitive generation market. As the Commission explained in D.97-09-048, in which it established the criteria for determining eligibility for transition cost recovery for generation capital additions generally:

> [T]he Legislature has given us latitude to adopt one or a combination of approaches for determining the reasonableness of transition cost recovery for capital additions. In doing so, we keep foremost in our minds the objective of creating a level playing field for all market participants during the transition to a fully competitive electric services industry. How we handle the issue of capital additions is a critical aspect of creating this level playing field. We do not wish to establish standards of reasonableness that afford utilities an unfair advantage in the market, particularly at ratepayers' expense. At the same time, we wish to encourage utilities to make cost-effective investments that will maintain the reliability of the electric system. As intended by [Section 367], utilities should have the opportunity to recover the costs of those investments during the transition period. (D.97-09-048, 75 CPUC 2d, 442.)

To implement the objectives of a level playing field and encouraging cost-effective investments that would maintain reliability, the Commission determined in D.97-09-048 that a "market control" approach was appropriate once the ISO and PX began functioning. The Commission determined that *ex post facto* reasonableness review was appropriate only for those capital additions made in 1996 and 1997. (As noted earlier, D.98-03-054 extended this period through March 1998.)

With the enactment of ABX1-6, we have new responsibilities to fulfill.[28] Where it was once the policy that utility generation would either be divested or subjected to market prices if retained, and that a level playing field be established by, among other things, preventing inappropriate ratepayer subsidies of generation offered into the market, Section 377 now requires that utilities retain their generation facilities at least through 2005, subject to Commission regulation. It further requires that we act to ensure that these generation facilities remain dedicated to service for the benefit of California ratepayers.

In D.02-11-026, we commented on how ABX1-6, including its amendment of Section 377, impacts Section 367. The following excerpt from that decision bears repetition here:

> These provisions of ABX1-6 clearly and expressly confer on the Commission jurisdiction over regulation of the utilities' retained generation assets, including rates. Such jurisdiction includes, for example, authority to determine whether and to what extent the utilities may recover in rates their investments in these retained generation assets. Moreover, by conferring upon the Commission the authority to continue to regulate the utilities' retained generation under a cost-of-service approach, and deleting provisions requiring generation to be transitioned from regulated to unregulated status, these provisions removed any danger that the investment in such assets "may become uneconomic as a result of a competitive generation market."[29] (§ 367.) In other words, the investment in

[28] The California Supreme Court has stated that ABX1-6 "constituted a major retrenchment from the competitive price-reduction approach of Assembly Bill 1890, reemphasizing instead PUC's duty and authority to guarantee that the electric utilities would have the capacity and financial viability to provide power to California customers." (*Southern California Edison Co. v. Michael R. Peevey* (2003) Slip Op. 11.)

[29] In a footnote at this point, the Commission explained that the concept of uneconomic costs is not applicable under cost-of-service ratemaking, and that the concept only has relevance under a market-based rate regime.

> these assets no longer is a stranded or transition cost within the meaning of AB 1890. Thus, recovery of these investments is no longer barred by AB 1890's prohibition on the recovery of stranded costs after the end of the rate freeze.[30] (D.02-11-026, pp. 13-14.)

No party has explained how we can fulfill our new obligation to ensure that SCE's coal and hydro facilities remain dedicated to service for the benefit of ratepayers through at least 2005 while limiting ratepayer funding responsibility only to those capital additions needed through 2001. Additionally, as we determined in D.02-11-026, the requirements of Section 367 are no longer applicable to the extent that those requirements conflict with those of ABX1-6. We also note that with the enactment of ABX1-6, utilities do not have the opportunity they previously had to recoup through divestiture capital investments that are not funded by ratepayers.

It follows that we must now provide for the utility's opportunity to recover the reasonable costs of maintaining and operating those facilities through 2005. It is no longer appropriate to hold the utility to the Section 367 requirement that capital additions be necessary to maintain the facilities only through 2001, or to the D.97-09-048 requirement that capital additions to improve the unit's heat rate be excluded. Doing so could deny the utility the opportunity to recover its reasonable costs for capital additions that benefit ratepayers, and it would be no more appropriate than it would be to adhere to the requirement that post-1998

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[30] In a footnote at this point, the Commission stated that "[a]lthough we believe that ABX1-6 and AB 1890 can be harmonized in this manner, to the extent that they cannot, ABX1-6 as the later-enacted statute, implicitly repealed those provision of AB 1890 that are incompatible with it. (*Peatros v. Bank of America* (2000) 22 Cal.4th 147, 167-68; *In re Thierry S.* (1977) 19 Cal.3d 727,744.)"

capital additions considered in this GRC be subjected to the now-irrelevant market control approach.

ORA and TURN state the correct rule for retrospective (*ex post facto*) reasonableness reviews generally, as applicable to capital additions -- reasonableness should be evaluated on the basis of facts and circumstances known or knowable when the utility made the decision to make the addition. However, for the reasons explained above, ABX1-6 has changed how we must evaluate these capital additions. We find that this general rule for reasonableness review is inapplicable in the current circumstances. Accordingly, we will not hold SCE to the requirement that the 1997-98 capital additions be necessary to maintain the facilities through 2001, or to the requirement that capital additions made to improve a unit's heat rate be excluded.

Appropriately, SCE no longer requests CTC recovery of the 1997-98 capital additions at issue here. Instead, SCE requests authorization to include these additions in rate base, just as the other generation capital additions considered in this GRC are. We will adopt this approach for the coal and hydro capital additions that we find to be reasonable, as discussed below. For the reasons discussed earlier these, are not "uneconomic" costs within the meaning of Section 367, and we reject TURN's assertion that Section 367(a) prohibits their recovery in this GRC.

In its reply brief TURN raises the concern that SCE may be seeking double recovery of capital additions to the extent that such costs are currently included in rate base pursuant to D.02-04-016. SCE's testimony (Exhibit 71, Section VII) appears to adequately explain the company's ratemaking proposals. Nevertheless, to avoid any possibility of double recovery, SCE should include in the advice letter filing it makes pursuant to this order a demonstration that the costs associated with these capital additions for 1997 and 1998 are included in rate base only once.

#### 3.7.3. Cost-Effectiveness Analyses

SCE maintains that all of the 1997-98 capital additions projects transferred to this docket were cost-effective using reasonable assumptions. For its cost-effectiveness analyses, SCE assumed that capital additions costs would be paid back over the economic life of the addition or the economic life of the plant in which it was installed, whichever was shorter. SCE limited the economic life used in its cost-effectiveness analyses to no greater than 20 years for hydroelectric projects and coal projects evaluated prior to May 1996. For coal projects evaluated in May 1996 and thereafter, SCE limited the economic life used in its cost-effectiveness analyses to no greater than 10 years. Using these payback periods, SCE determined that all projects had benefit-to-cost ratios greater than 1.0, i.e., all projects had more benefits than costs.

ORA and TURN advocate payback periods of six years and 7-10 years respectively. These shorter payback periods affect the cost-benefit analyses for several projects, leading to substantial recommended disallowances.

***Discussion***

In D.99-03-055, the Commission found that a 20-year payback assumption is reasonable for 1996 capital additions. The Commission did, however, indicate that it would consider different payback periods for subsequent investments in generation plant.

The shorter payback period advocated by ORA for 1997 and 1998 capital additions is premised upon the ORA position that " [a] long-term useful life assumption is unreasonable and inconsistent with a decision to divest…" (Exhibit 229, Appendix B, p. 2-3.) TURN similarly contends that the shorter payback periods it recommends are appropriate in light of the advent of industry restructuring. Since we have determined that it is appropriate to evaluate the subject capital additions according to GRC criteria, and not the stricter standards of Section 367 and D.97-09-048 that were associated with the transition to a more competitive generation market, we find that the shorter payback periods advocated by ORA and TURN are not properly applicable here. Their recommended project disallowances that are based upon the shorter payback periods will not be adopted. The appropriate way to measure the cost-effectiveness of a capital addition is to review its benefits over the remaining life of the generating station or the life of the capital addition, whichever is shorter.

#### 3.7.4. Performance Improvements

ORA and TURN recommend disallowances of SCE's capital additions for which significant efficiency improvements resulted. ORA did not include benefit/savings from enhanced unit performance when the percent of total benefit/savings was greater than 50%. TURN found that heat rate benefits accounted for nearly 70% of the total benefits from Mohave centrifuge projects, and recommends disallowance of the associated capital additions.

SCE responds that its capital additions meet the heat rate standard set forth in D.97-09-048 because none of the projects resulted in a significant improvement to the generating *unit's* heat rate even though, for some projects, a significant portion of the *project's* benefit was due to heat rate improvements.

***Discussion***

In this GRC, for the reasons discussed previously, we are not enforcing the heat rate standard adopted in D.97-09-048. Accordingly, we will not adopt recommended disallowances to the extent that those disallowances are based upon the asserted failure of a project to meet the standard.

### 3.7.5. Budget Variances

ORA identified 10 hydro projects for which actual project expenditures exceeded SCE's budget by more than 10%. In some cases the budget overruns were substantial – as much as 416%. For six of these projects, ORA recommends disallowances solely on the basis of the budget variances. For the other four projects, ORA recommends disallowances on the basis of unfavorable benefit/cost ratios as well as budget variances.

SCE introduced evidence showing that for the six projects for which ORA recommended disallowances solely on the basis of budget variance, the projects had benefit/cost ratios greater than one. SCE contends that merely because a project varies from budget does not mean it was not cost-effective. For the other four projects for which ORA bases its recommended disallowances on both inadequate benefit/cost ratios and budget variances, SCE has shown that the benefit/cost ratios exceed one.

***Discussion***

The record evidence shows that the subject hydro projects are cost-effective in that their benefit/cost ratio exceeds one. Since the benefits exceed the costs, thereby benefiting ratepayers, we will not disallow the projects' capital costs on the basis of budget overruns.

### 3.7.6. Project Timing

ORA takes the position that SCE is entitled to receive recovery for capital additions completed after December 31, 1996 and before April 1, 1998. ORA recommends disallowances for projects completed after March 31, 1998. According to ORA, these projects are not eligible for cost recovery by Commission authorization, but SCE may seek and obtain recovery through competitive market revenues. For example, a project to replace a road and parking lot destroyed by storm flooding at the Mammoth Pool Powerhouse had a work order completion date of August 1998, so ORA recommends disallowance of $392,000 in capital additions associated with the project.

SCE contends that it has requested recovery only for capital additions that were completed and in service during the period from January 1, 1997 through March 31, 1998. SCE further contends that the date that a work order is closed is immaterial. If there is a portion of work in a work order that is completed and in operation, then that portion is closed to plant in accordance with FERC accounting rules.

***Discussion***

SCE has shown that during the period of time between the opening of a work order and its closure, there could be many capital closings to plant in service. The fact that certain work orders associated with the 1997-98 projects at issue in this GRC were closed after March 31, 1998 does not demonstrate that SCE has impermissibly sought capital cost recovery for projects outside the scope of this proceeding. ORA's proposed disallowances that are based upon assertions of improper timing will not be adopted.

#### 3.7.7. Casualty Loss Projects

For recovery of project costs related to plants damaged by flood, fire, etc., ORA recommends allowing only 60% of the projects' costs. ORA reasons that SCE can claim the loss on its income tax return, and that since the company's tax rate is approximately 40%, SCE should be allowed recovery of only 60% of the capital additions cost.[31] SCE contends that these 40% disallowances are improper.

***Discussion***

Casualty losses are tax benefits associated with the early retirement of capital assets. The amount of a casualty loss is measured by the remaining undepreciated basis of the asset, not the cost to replace the asset. Casualty losses are deductible for income tax purposes, and benefit ratepayers. Because the benefit of a casualty loss goes to ratepayers, the benefit does not provide for recovery of the cost to replace the asset. ORA's proposed 40% disallowances are therefore improper, and will not be adopted.

#### 3.7.8. Conclusion – 1997-98 Capital Additions

We have not found it necessary to examine in detail whether each of the generation capital additions that SCE made in 1997-98 fully complies with the Section 367 requirement that the additions be necessary to maintain the generation facility through December 2001. We also have not examined in detail whether certain of the disputed capital additions contributed substantially to the efficiency of the plants' operations. This is because ABX1-6 has changed how we must evaluate the reasonableness of the capital additions and their eligibility for cost recovery from utility ratepayers.

The provision of amended Section 377 requiring that we ensure that utility-retained generation facilities remain dedicated to service for the benefit of ratepayers means that we must give reduced or no weight to previous review

[31] SCE's insurance deductible is $2 million. No party contends that insurance proceeds are available to reimburse SCE for the projects' costs.

requirements that were intended to promote a competitive generation market. Even if it would have been appropriate to deny recovery of otherwise reasonable capital additions because they did not meet the standards of Section 367 and D.97-09-048, it would now be inappropriate to deny recovery of cost-effective capital additions that are consistent with Section 377's dedicated service requirement.

With respect to the GRC standards applicable here, SCE has made a showing of reasonableness for the 1997-98 generation capital additions underlying its request for $30.937 million. SCE's request will be approved.

## 4. Transmission and Distribution (T&D)

### 4.1. Introduction

When California's electricity industry restructuring program was implemented in 1998, SCE transferred operational control of its transmission facilities to the ISO, subject to FERC regulation. SCE's distribution and subtransmission facilities remain under this Commission's jurisdiction. SCE's showing in this GRC includes a total O&M and capital forecast for both Commission and FERC jurisdictional T&D facilities. A transmission revenue credit offsets the costs of FERC jurisdictional transmission assets and the associated O&M expenditures.

SCE's Transmission and Distribution Business Unit (TDBU) manages the company's T&D facilities. The TDBU has approximately 4,400 full-time employees who plan, design, construct, operate and maintain approximately $11.3 billion in utility assets. The SCE system serves 4.4 million customers over a 50,000 square mile service territory, and includes approximately 1.5 million poles, 95,000 circuit miles of wire, 306,000 underground structures, 667,000 transformers, 43,000 switches, and 750,000 streetlights.

SCE forecasts $274.7 million (2000 dollars) for T&D O&M expenses for test year 2003.[32] SCE also forecasts more than $2 billion for new capital expenditures during the years 2001 through 2003. ORA recommends a $7.6 million O&M expense reduction ($1.5 million transmission and $6.1 million distribution) and a $459 million reduction in plant additions.[33] TURN recommends a $1.7 million O&M expense reduction, a $29.7 million reduction in 2002-2003 capital additions, and a penalty of at least $48.8 million and as much as $61 million for SCE's alleged failure to adequately manage its wood pole inspection and replacement program. In addition, TURN has offered recommendations regarding SCE's line and service extension rules. Section 4 of this decision addresses these issues as well as contested issues regarding SCE's funding request for electric transportation.

### 4.2. Level of Reliability Performance

As measured by Average Customer Minutes of Interruption (ACMI) and Frequency of Circuit Interruptions, SCE's year 2000 reliability performance was among the best of the past 15 years. SCE's ACMI over the years 1996-2000 was 56.32 minutes, an improvement of 2.86 minutes compared to the 15-year average of 59.18 minutes. The five-year average of frequency of circuit interruptions was 9,546, a reduction of 512 interruptions from the 15-year average of 10,058.

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[32] The Joint Comparison Exhibit shows SCE's forecast for transmission O&M as $76.647 million and its forecast for distribution O&M as $230.608 million, or a total T&D O&M forecast of $307.255 million. (Exhibit 403, pp. 241-42.)

[33] The Joint Comparison Exhibit shows the difference between SCE's and ORA's distribution O&M forecasts as $22.997 million. (Exhibit 403, p. 242.)

SCE states that it is not seeking to enhance reliability through its T&D funding request in this GRC. Instead, SCE maintains, its requested funding level is necessary to avoid a significant degradation of the current level of reliability and to avoid significantly higher replacement costs.

ORA agrees that SCE generally provides reliable service to customers over its T&D system. In fact, ORA believes there is reason to be concerned that SCE's reliability may actually be too high, and that rates may therefore be too high. ORA states the following:

> Reliability costs ratepayers money, as Edison has reminded us during the rate case. That is why the reasonable rates requirement is at tension with reliable service. Edison has not assessed, at least for this rate case phase, how different customers and customer classes value reliability. How much decreased reliability would customers accept in exchange for more reasonable rates? The evidence provides no answer, although we know that Edison customers are less than happy about their rate levels. (ORA Opening Brief, p. 33.)

ORA proposes that we require SCE to provide a comprehensive report with its next GRC application that provides detailed evidence on the specific monetary trade-off associated with specific reliability levels, and also provides empirical findings on customer willingness to accept lower reliability in return for lower rates. ORA also proposes that SCE's next GRC be used to review and address whether all customers receive a similar level of service for the rates they pay as do other customers in the same customer class.

***Discussion***

SCE's T&D policy witness testified that the company's reliability is generally high, customer satisfaction is moderately rising, controllable costs are moderate, and that "[w]e have accomplished this balanced performance through our focus on long-term planning, management oversight, and a commitment to long-term investments." (Exhibit 21, p. 3.) Unfortunately, it is not clear whether the planning, management and oversight performed by SCE's TDBU executives is adequately informed by empirical analyses such as those proposed by ORA.

It may be theoretically possible to create an overly reliable T&D system that adds unnecessarily to ratepayer costs. In other words, ratepayers might be willing to accept somewhat diminished reliability performance if sufficient rate reductions could be realized in return. As noted earlier in this decision, we are mindful that SCE's retail prices are comparatively high according to several standards, and that high rates are harmful to ratepayers and the California economy. We therefore accept ORA's proposal to carefully consider the issue of the costs and benefits of T&D service reliability in SCE's next GRC. We emphasize that nothing in the evidentiary record before us shows that SCE's T&D system is in any sense "too reliable" or that any significant cost savings could necessarily be expected from a decision to target reduced reliability levels. We suggest that SCE and ORA confer on this issue before SCE makes its next GRC filing, so that SCE has an opportunity to understand and address ORA's concerns in its direct showing.

SCE notes that it performed a value-of-service study in 2000, and claims that ORA's proposal for a showing in the next GRC is therefore moot. We will direct SCE to include cost/reliability tradeoff and value-of-service analyses with its next GRC filing that address the concerns raised by ORA. If SCE believes that its 2000 study adequately addresses these concerns, it is free to offer that study in fulfillment of this requirement. In the event that SCE does so, it will be incumbent upon it to show that the study remains valid despite the passage of time, and otherwise fulfills this requirement.

We find no record evidence prompting us to comment on ORA's request that SCE's next GRC be used to examine whether all customers receive a similar level of service. ORA may wish to raise this issue at the commencement of SCE's next GRC. We also suggest that SCE and ORA confer on this issue before SCE makes its next GRC filing, so that SCE has an opportunity to understand and address ORA's concerns in its direct showing.

## 4.3. Wood Pole Inspections

### 4.3.1. Introduction

TURN, which is "extremely critical" of SCE's past T&D maintenance practices (TURN Opening Brief, p. 42), asks that we impose a penalty for deferred pole maintenance of at least $48.8 million and as much as $61 million. As grounds for this penalty, TURN contends that SCE failed to adequately manage its wood pole inspection and replacement program over the past 20 years. TURN also recommends that SCE's shareholders be required to contribute more than $1 million annually to fund approximately 30,000 annual intrusive pole inspections, while ratepayers would fund 95,000 inspections per year. TURN also requests that SCE be directed to report annually on intrusive pole inspections completed in the prior year.

### 4.3.2. Historical Pole Inspections

Underlying TURN's proposed penalty and its related recommendations is a two-decade pattern of ratemaking authorizations for pole inspections and SCE's actual spending on inspections during the period. Before addressing TURN's recommendations, we examine disputed factual contentions associated with TURN's analysis, which is summarized in the following table.

## TURN's Analysis of Number of Intrusive Pole Inspections: Ratepayer Funded and Completed

| Year | Funded Inspections | Completed Inspections | Cumulative Funded | Cumulative completed | Annual excess | Cumulative excess |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e)=(a)-(b) | |
| 1984 | 77,800 | 50,864 | 77,800 | 50,864 | 26,936 | |
| 1985 | 77,800 | 66,248 | 155,600 | 117,112 | 11,552 | |
| 1986 | 77,800 | 48,155 | 233,400 | 165,267 | 29,645 | |
| 1987 | 77,800 | 22,197 | 311,200 | 187,464 | 55,603 | |
| 1988 | 66,248 | 37,239 | 377,448 | 224,703 | 29,009 | |
| 1989 | 66,248 | 11,367 | 443,696 | 236,070 | 54,881 | |
| 1990 | 66,248 | 47,315 | 509,944 | 283,385 | 18,933 | |
| 1991 | 66,248 | 54,539 | 576,192 | 337,924 | 11,709 | 238,268 |
| 1992 | 30,000 | 8,821 | 606,192 | 346,745 | 21,179 | |
| 1993 | 30,000 | 0 | 636,192 | 346,745 | 30,000 | |
| 1994 | 30,000 | 0 | 666,192 | 346,745 | 30,000 | 81,179 |
| 1995 | 113,000 | 51,371 | 779,192 | 398,116 | 61,629 | |
| 1996 | 113,000 | 67,508 | 892,192 | 465,624 | 45,492 | |
| 1997 | 113,000 | 90,609 | 1,005,192 | 556,233 | 22,391 | |
| 1998 | 113,000 | 47,486 | 1,118,192 | 603,719 | 65,514 | |
| 1999 | 113,000 | 9,476 | 1,231,192 | 613,195 | 103,524 | |
| 2000 | 113,000 | 102,991 | 1,344,192 | 716,186 | 10,009 | |
| 2001 | 113,000 | 120,796 | 1,457,192 | 836,982 | -7,796 | |
| 2002 | 113,000 | 125,000 | 1,570,192 | 961,982 | -12,000 | 288,763 |
| TOTALS | 1,570,192 | 961,982 | | | | 608,210 |

SCE's 1983 "Deteriorated Pole Report" incorporated the idea that a strategic, cost-minimizing program would optimize maintenance versus capital investments by coordinating pole inspections, pole repairs and pole replacements. That study was the genesis of SCE's pole inspection, repair and replacement programs. It recommended intrusive inspection[34] of all poles older than 20 years on a 15-year cycle, a goal adopted by the company and proposed and accepted in SCE's 1985 GRC.[35] It resulted in the recommended inspection of 77,800 poles annually. At the heart of the current issue is TURN's contention that beginning in 1984, SCE repeatedly deferred spending on the pole inspections envisioned in this program so that by 2002, the company had inspected only 961,982 poles, or about 61% of the 1,570,192 inspections that ratepayers funded during that period.

With respect to its contention that ratepayers funded more than 1.5 million intrusive inspections from 1984 to 2002, TURN's position is summarized below:

- During this time period SCE's rates were approved in five GRCs, with test years in 1983, 1985, 1988, 1992, and 1995. The Commission explicitly addressed funding for intrusive pole inspections in the 1985 and 1995 GRCs, and even though the Commission did not explicitly do so in the 1983, 1988, and 1992 GRCs, it is possible to determine the amounts implicitly authorized for intrusive inspections.
- In the 1985 GRC, the Commission explicitly approved 77,800 intrusive inspections annually for 1985-1997.
- In the 1995 GRC, the Commission approved 113,000 intrusive inspections annually from 1995 through 2002.
- In D.84-12-068 (the 1985 GRC decision), the Commission noted that in the 1983 GRC, SCE received funding for a deteriorated pole replacement program. As stated in the 1983 study, 77,800 inspections could be undertaken "within the parameters of the

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[34] Intrusive inspections involve boring into the pole to test its integrity, and a fungicide and insecticide treatment of poles that pass inspection. The treatment can extend a pole's life by 10-15 years.

[35] Exhibit 31, p. 31; D.84-12-068 (16 CPUC 2d 721, 781-82).

committed dollars in the 1983 rate case filing," and SCE's witness in this GRC agreed that the 1983 GRC funds were apparently adequate. TURN contends that it is reasonable to conclude that 77,800 inspections in 1984 were funded by ratepayers in the 1983 GRC.

- In the 1988 GRC, SCE's funding level was based on the 1985 recorded spending level. In 1985 SCE completed 66,248 inspections. TURN thus uses 66,248 inspections as the ratepayer funded level for 1988-1991.
- In the 1992 GRC, SCE was funded for at least 30,000 intrusive pole inspections per year for 1992-1994, as shown in evidence in SCE's 1995 GRC.

SCE takes issue with several aspects of TURN's analysis and conclusion that SCE completed only 61% of the intrusive inspections that ratepayers paid for, as discussed below.

***Discussion***

While it acknowledges that pole inspection forecasts were explicitly addressed in the 1985 and 1995 GRCs, SCE implies that neither forecasts nor commitments regarding pole inspections were made in the other GRCs over the past 20 years. However, TURN has demonstrated that it is unreasonable to make this assumption. Even when not explicitly addressed, SCE's T&D O&M costs have included a pole treatment and inspection component in every GRC beginning with the test year 1983 GRC. Moreover, it is possible to make an estimate of the number of pole inspections connected to funding received in the 1983, 1988 and 1992 GRCs, as TURN has done. This is consistent with evidence showing that SCE's prevailing policy for pole inspections from 1983 to 1997 was the strategy outlined in the 1983 study. The fact that SCE temporarily halted pole inspections in 1993 and 1994 in order to address a backlog of pole replacements does not change this conclusion.

Moreover, even though SCE's 1995 GRC was succeeded by a PBR mechanism in more recent years, it is reasonable to conclude that the level of pole inspections included in the 1995 GRC continued throughout the PBR period, since the GRC authorization was used as the base year for the PBR. Significantly, SCE's testimony in the 1995 GRC stated "starting in 1995 and continuing through 2003, we will schedule 113,000 pole inspections yearly until the remaining inventory of over one million uninspected poles have been inspected and treated."

While we can determine a reasonable estimate of the number of inspections that have been funded by ratepayers over the past two decades, TURN's contention that all of these inspections were to be intrusive is not supported by the record. The 1983 study on wood poles recommended that three categories of poles undergo an intrusive type inspection: those in service for 20 years or longer, second hand set poles, and Cellon poles. Other poles would undergo visual inspection only. SCE has demonstrated that that the 77,800 annual inspections forecast in the 1985 GRC and the 113,000 annual inspections forecast in the 1995 GRC included visual-only inspections as well as intrusive inspections. This was confirmed by an SCE rebuttal witness who was familiar with the 1983 study and testified that it was SCE's intent to intrusively inspect only a subset of the poles it would visually inspect each year.

Unfortunately, the witness did not specify the size of the subset. However, given the age of SCE's pole inventory, it is clear that the majority of the T&D poles were and are greater than 20 years old and would therefore have qualified for intrusive inspections under SCE's criteria. TURN points to evidence that only 20% of SCE's poles were in service less than 20 years. We will use this data to correct TURN's estimate of the number of intrusive inspections reflected in the

GRC forecasts for the last 20 years. Accordingly, we will reduce TURN's calculation of 1,570,192 total inspections by 20% to arrive at a corrected estimate of 1,256,154 intrusive inspections funded in GRCs over the past 20 years. We note that this estimate is conservative (i.e., it favors SCE) because it does not account for second hand set poles and Cellon poles.

SCE points out that the approval of General Order (GO) 165 with an effective date of March 1, 1997 impacted its obligation to perform intrusive inspections. SCE contends that in light of the new obligations created by GO 165, TURN errs when it asserts that SCE's forecast of inspecting 113,000 poles per year extended beyond the 1995 GRC cycle. This contention is without merit. Nothing in the GO 165 requirement to intrusively inspect wood poles older than 15 years by 2007 affected the forecast of 113,000 visual/intrusive inspections per year underlying SCE's ratemaking authorization. As the Commission stated in D.97-03-030, which adopted GO 165, the new standards were maximum acceptable lengths for inspection cycles. Nothing in GO 165 suggested that SCE should slow the pace of intrusive inspections that was set in the 1995 GRC and continued through the PBR mechanism.

#### 4.3.3. Proposed Penalty

We have determined that over a period of nearly 20 years and five GRCs, SCE received funding authorization associated with forecasts for 1,570,192 pole inspections. We have also determined that an estimated 80% of these inspections, or 1,256,154 million, were to be intrusive inspections that included a treatment to extend the pole life. During that same period, exercising its managerial discretion to devote authorized funds to other uses, SCE actually completed 961,982 intrusive inspections, or 77% of the funded level. We next consider whether this performance by SCE constitutes wrongdoing for which a penalty is appropriate. We then consider (in Section 4.3.4) whether a ratemaking disallowance should be adopted in this GRC as a result of this performance.

***Discussion***

It is a fundamental tenet of forecast test year ratemaking that inclusion of a particular expense category in a GRC authorization does not create a specific obligation for the utility to spend the authorized amount during the test year. Thus, utility management is generally provided discretion regarding use of funds and is not bound by the adopted forecast.[36] However, as we observed previously in this decision, the Commission held in an SDG&E GRC that there are limits to that management discretion:

> When a utility's expense estimate includes the performance of a task it had planned to accomplish with previously authorized funds, we will want to know why the utility did not spend its funds as planned the first time around and will be hesitant to charge ratepayers twice for the same expense. (D.92-12-019, 46 CPUC 2d 538, 555.)

More recently, in PG&E's test year 1999 GRC, the Commission once again addressed the problem of deferred maintenance and a utility's failure to perform activities that have been funded by forecasts adopted by the Commission:

> It would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonably deferred maintenance, or to make ratepayers pay a second time for

[36] There are exceptions to this principle. For example, in PG&E's 1999 GRC, we approved funding for tree trimming using a one-way balancing account whereby the amount ultimately collected by the utility is subject to true-up to the extent that authorized revenues exceed actual expenses. (D.00-02-046, p. 148.)

> activities explicitly authorized by the Commission in the past. (D.00-02-046, Conclusion of Law 15, p. 536.)

SCE has provided no reason why we should exempt it from these ratemaking principles, and we will not do so. With respect to intrusive pole inspections, SCE's exercise of its managerial discretion over a period of nearly 20 years has led to a situation in which the company has completed an estimated 77% of the intrusive inspections for which it received funding through the GRC / PBR ratemaking process. This raises the question whether SCE is seeking funding in this GRC for pole inspections that could have and should have been performed already with previously authorized funds. We will return to this ratemaking question, but we first consider whether any aspect of the 23% shortfall in completed intrusive inspections warrants the imposition of a penalty as proposed by TURN.

This is not the first occasion we have had to critically review SCE's management of its pole inspection program. In the 1995 GRC, taking into account overriding safety concerns, the Commission rejected a proposal to reduce expenses for SCE's forecast level of inspections. However, the Commission imposed annual reporting requirements regarding the number of inspections completed in 1995, 1996, and 1997, and stated that it would consider imposing penalties on SCE for compromising the safety of its distribution system if, at the end of each of those years, SCE had failed to meet its inspection target for the year. (D.96-01-011, 64 CPUC 2d, 282, 392.)

Utilities are required to comply with relevant statutes, Commission GOs, and decisions, and the Commission has the statutory obligation to require utilities to do so. (*See,* e.g., Pub. Util. Code §§ 702, 2101 and 2106.) A utility's failure to comply with these statutes, GOs and decisions means a utility has violated them. The Commission may impose a penalty upon a utility when a violation by that utility has occurred.[37] With respect to the penalty proposed by TURN, the relevant Commission orders are a series of ratemaking decisions issued in five GRCs over a period of 20 years.

Notwithstanding SCE's failure to achieve its planned and funded pole inspection targets over the past 20 years, and the fact that SCE was on notice that it might incur a penalty if it failed to perform the target number of inspections in 1995, 1996, and 1997, we do not find that imposition of a penalty for this failure is justified.

We cannot find that a utility has failed to comply with, and therefore violated, a Commission order to perform a certain number of inspections within a certain time period unless the order actually exists, or at a minimum, can be readily discerned from the decision adopting the order. With the exception of Ordering Paragraph 15 of D.96-01-011 in SCE's 1995 GRC, no reasonable argument can be made that over the past two decades SCE was under a specific mandate pursuant to a GRC decision to perform a given number of intrusive inspections in a particular time period.[38] If we cannot find that SCE failed to

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[37] When the Commission imposes a fine or penalty upon a utility for violation of a statute or order, the proceeds are deposited in the General Fund of the State of California. (*See* D.98-12-075, 84 CPUC 2d 155, 182: "The purpose of a fine is to go beyond restitution to the victim and to effectively deter further violations by this perpetrator or others. For this reason, fines are paid to the State of California, rather than to victims.") Thus, TURN's proposed penalty would not "compensate" ratepayers.

[38] We have already noted that during the latter part of the 20-year period analyzed by TURN, GO 165 was adopted and established new inspection requirements.

comply with an order to perform inspections, no violation has occurred warranting the imposition of a penalty.

In addition, there is a significant timeliness issue with TURN's penalty recommendation. In effect, it requires that we hold that SCE has failed to comply with a Commission order or orders with respect to acts or omissions that occurred as long as 20 years ago. Even with respect to D.96-01-011, where we placed SCE on notice that it was subject to penalties, we are asked to determine whether SCE complied with inspection requirements by acts or omissions that occurred in 1995, 1996, and 1997. Put simply, too much time has elapsed for us to determine fairly whether a violation has occurred. Indeed, the need to contemporaneously evaluate compliance is consistent with the D.96-01-011 requirement for annual reporting on completed inspections by March 1 of the succeeding year. Bringing a penalty action in December of 2002 (when TURN submitted its testimony in this GRC) is inconsistent with due process requirements of an enforcement action.

#### 4.3.4. Ratemaking Adjustments for Deferred Inspections

Although we have determined that imposition of a penalty for SCE's pole inspection management practices is not justified, SCE's failure to perform an estimated 23% of the intrusive inspections it was funded to complete over two decades requires further consideration. This is necessary to ensure that ratepayers are not required to pay a second time for activities explicitly authorized by the Commission in the past, and to ensure that ratepayers are not held responsible for costs that are directly attributable to deficient or unreasonably deferred maintenance practices.

***Discussion***

We first consider whether SCE's funding request for intrusive inspections would represent "double charging" for previously funded activities. Second, we will determine whether SCE's proposed capital expenditures include pole replacements that would have been unnecessary in this GRC cycle if intrusive inspections had been timely completed in the past.

As to the first question, TURN recommends that SCE's request for funding for 140,000 intrusive inspections annually be reduced by 44,500 to 95,500 intrusive inspections. This results in a proposed disallowance of $1.7 million (2000 dollars), or approximately $38 per inspection. In addition to 95,500 ratepayer-funded inspections, TURN recommends that SCE be directed to perform 30,000 intrusive inspections annually at shareholder expense for a total of 125,500 inspections. TURN states that the 90,000 shareholder-funded intrusive inspections that would be performed over the three-year GRC cycle would partially offset the inspection "deficit" of 317,000 funded but non-completed inspections since the last GRC, so that ratepayers do not pay twice for inspections.

In its rebuttal testimony, SCE determined that it needs to perform an average of 125,000 intrusive inspections per year through 2006 to meet the requirements of GO 165. Thus, for what appear to be different reasons, SCE and TURN are in virtual agreement with respect to the number of annual intrusive inspections that need to be performed in this GRC cycle (125,000 v. 125,500). Their disagreement is over funding responsibility. We will adopt SCE's estimate of 125,000 annual intrusive inspections as necessary and adequate to achieve compliance with GO 165.

The main premise of TURN's recommended disallowance, the idea that shareholders should fund a portion of the required number of inspections, is the correct one because it gives effect to the principle that ratepayers should not be required to pay twice for the same authorized expense. Even if it was appropriate for SCE exercise its spending discretion in order to address emergent issues in any one year, it is also reasonable and appropriate to hold SCE accountable for completing the pole inspections that ratepayers paid for over a longer period. This is especially true beginning with the issuance of D.96-01-011 in January 1996, when SCE was on notice that, for safety reasons, we fully expected that the funded inspections were to be timely completed.

We will adopt TURN's approach for addressing the "double charging" problem, along with corrections and modifications, as follows. First, we are reluctant to reach back over several GRC cycles to address underperformance that could have and should have been addressed previously. We will instead focus on the period 1996-2002, i.e., the period following the issuance of the 1995 GRC decision in January 1996. We determine that SCE was funded to perform an estimated 632,800 intrusive inspections during this period (113,000 annual inspections, 80% of which are estimated to be intrusive, times seven years.) During the same period SCE performed 563,866 such inspections (67,508; 90,609; 47,486; 9,476; 102,991; 120,796; and 125,000, respectively, in 1996, 1997, 1998, 1999, 2000, 2001, and 2002). The difference, 68,934, represents the number of inspections that were funded for the seven-year period but not performed. We will disallow the costs for that number of inspections over the current three-year GRC cycle. Accordingly, we disallow $2.619 million for intrusive inspections that have already been funded by ratepayers (68,934 times $38 per inspection), or $873,164 annually. In addition, we will remove $570,000 annually (15,000 times $38 per inspection) to reflect SCE's estimate of 125,000 required inspections in lieu of its requested funding for 140,000 inspections. The total adjustment is

$1.443 million per year for FERC Account 583.400, Inspections. While we adopt this ratemaking adjustment, SCE must fully comply with GO 165 inspection requirements.

In addition to showing that SCE has performed fewer inspections than it was funded for, TURN has demonstrated that, because intrusive pole inspections were delayed, SCE missed an opportunity to extend the life of those poles and reduce future replacement costs. SCE contends that pole treatments simply reduce the frequency at which poles will be replaced. We accept this assertion, but we are not so dismissive of the benefit of reducing the replacement frequency. SCE acknowledges that a pole's life can be extended 10 to 15 years with an intrusive inspection that includes treatment. The fact remains that SCE now has to replace poles that otherwise would have remained in service had they received timely fungicide treatment.

SCE also claims that TURN fails to recognize the prior useful life of poles whose inspections were delayed for a short period of time, and that TURN erroneously concludes that a missed pole treatment creates a cost to SCE ratepayers amounting to the entire cost of a pole replacement. This claim is without merit, as TURN puts forth no such conclusion. Similarly, even if SCE's contention that "short delays in the application of insecticide/fumigant treatments have minimal impact on pole life" were true, an inspection that has not been performed at all between 1996 and 2002 is not evidence of a short delay. Again, this contention is inapposite. SCE's delays in completing pole inspections do not merely represent "minor slippage" as the company claims.

TURN has calculated that each missed intrusive inspection translates into a current pole replacement cost of approximately $330 after 20 years, or a net present value of $59 at 9%, and on the basis of this calculation it proposed that a penalty of at least $50 be imposed for each missed inspection. Although we do not impose a penalty, TURN's analysis remains valid for purpose of calculating a ratemaking adjustment to offset the unreasonably high costs of pole replacements that result from SCE's failure to timely perform inspections from 1996 to 2002.

Based upon the foregoing, we will reduce SCE's capital forecast for pole replacements by $3.447 million (68,934 intrusive inspections that were funded by ratepayers but not performed by SCE times $50 per missed inspection). This disallowance is directly attributable to SCE's deficient or unreasonably deferred maintenance practices, i.e., its failure to perform intrusive inspections that it was funded and required to perform.

#### 4.3.5. Reporting Requirement

TURN proposes that SCE be directed to report annually on the number of intrusive pole inspections completed in the prior year.

***Discussion***

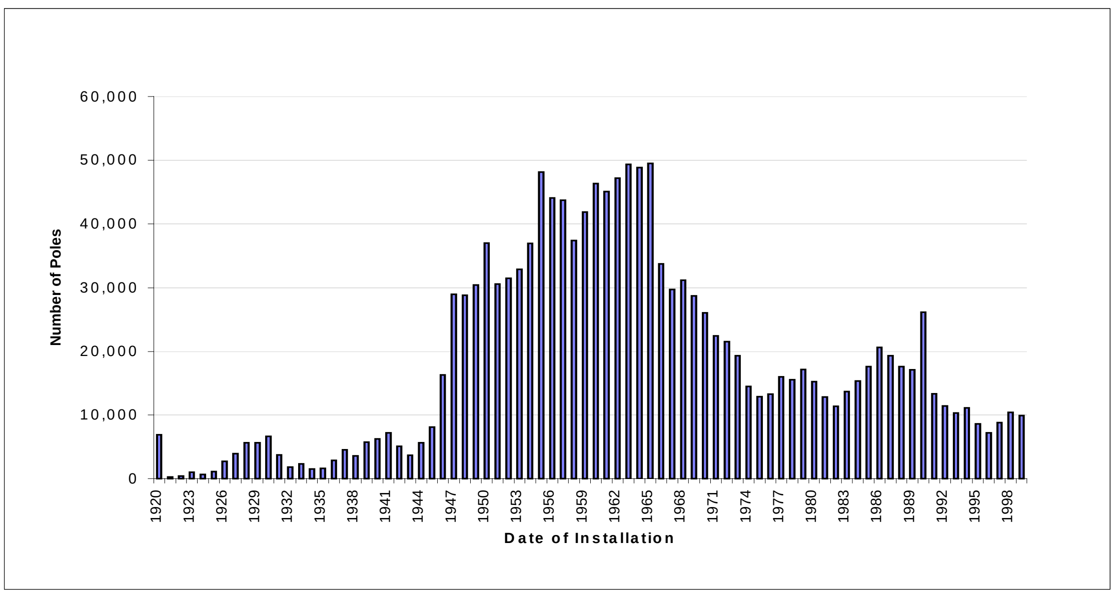
This recommendation in effect asks that we reinstate the three-year reporting requirement that we imposed in D.96-01-011, Ordering Paragraph 15. However, in the intervening period the Commission has adopted GO 165, which governs inspection practices. We are hesitant to overlay GO 165 requirements with additional reporting requirements. In addition, SCE will need to address the status of its pole inspection program in its next general rate case. We are not persuaded that additional reporting is required in this GRC docket. This proposal will not be adopted.

### 4.4. T&D Capital

#### 4.4.1. Introduction

SCE's T&D policy witness testified that the company's plan to invest more than $2 billion in T&D capital additions between 2001 and 2003 includes what he characterized as an aggressive capital replacement program to minimize the adverse consequences of SCE's aging system. SCE refers to this replacement program as the Infrastructure Replacement (IR) program. The IR program is budgeted for $621.938 million in 2001-2003, with wood distribution pole replacement accounting for $181.6 million of this total. The figure below depicts the wood pole "age bubble" that is addressed by the IR program.

**Current Inventory Of Wood Poles**
**By Date Of Installation**




### 4.4.2. ORA's Plant Recommendations

SCE forecast T&D plant additions of $614.399 million in 2001, $718.166 million in 2002, and $811.209 million in 2003, or a three-year total of $2.144 billion. ORA estimated additions of $456.728 million in 2001, $509.407 million in 2002, and $561.311 million in 2003, or a three-year total of $1.527 billion. SCE stipulated to a reduction of $157.761 million for 2001. Thus, ORA's three-year plant additions estimate is lower than that of SCE by $458.657 million ($208.759 million for 2002 and $249.898 million for 2003.)

SCE based its T&D plant additions forecast on a budget-based plan of expenditures. ORA compared SCE's forecast with recorded gross plant additions for 2001 and the first half of 2002, and determined that recorded additions were 25.7% less than forecast for 2001 and 35.3% less than forecast (on an annualized basis) for 2002. ORA concluded that SCE's capital budget was not an accurate basis for developing plant additions for 2001 and 2002, and should not be used to forecast plant additions for 2003. ORA believes that it is more appropriate to use actual, recorded plant additions to forecast additions for 2002 and 2003.

***Discussion***

ORA does not question the reasonableness of any particular T&D capital spending item associated with SCE's budget-based forecast. Instead, ORA questions whether the full amount of SCE's forecast capital spending for 2002 and 2003 will occur during that period. ORA relies on the fact that SCE's plant additions in 2001 and early 2002 were below the level of SCE's forecast to conclude that plant additions in late 2002 and 2003 will similarly be below budget. However, the evidence does not support this conclusion.

Even though T&D plant additions were lower than forecast for 2001 and 2002, that was an anomalous period. In 2001, SCE temporarily reduced capital spending because of the company's financial condition brought on by the energy crisis. This delayed many T&D projects that were nearing completion, which delayed the closing of those projects' work orders to plant in service. This in turn resulted in a $158 million shortfall in the 2001 T&D plant addition target. The problem persisted into early 2002 because of additional capital spending deferrals associated with the financial crisis. However, despite the additional deferrals, SCE was able to complete and record $723 million in actual T&D plant additions in 2002, exceeding the GRC forecast by $5 million.

SCE's plant additions were lower than forecasted because the coordination and completion of paperwork involved in closing these capital expenditures to plant in service was delayed for several non-recurring reasons. Significantly, however, T&D capital expenditures during 2001-2002 were $2 million above the amount that SCE forecast in the GRC application. In other words, SCE has actually incurred the capital expenditures that it is requesting in this proceeding.

SCE has stipulated to the reduced plant additions recorded in 2001, and it has exceeded its 2002 target in plant additions. Apart from speculation that SCE accelerated closings to plant in 2002 in part because the GRC was pending, which speculation we discount, no reason has been shown why this trend will not continue into 2003. Since no issue as to the reasonableness of SCE's budget-based forecast of T&D plant additions has been raised (except for pole replacement costs), and SCE was on target to spend the budgeted amounts, we conclude that its T&D capital forecast is more reliable and should therefore be adopted along with the pole replacement cost adjustments discussed previously and in the following section.

#### 4.4.3. Wood Pole Replacement Costs

SCE's T&D capital forecast includes estimated capital expenditures of $72.315 million in 2002 for 9,000 wood pole replacements and $76.509 million in 2003 for 9,300 replacements. Finding SCE's per pole replacement cost of $7,661 (year 2000 dollars, $8,228 in 2003 dollars) to be excessive, TURN recommends adoption of a substantially lower unit cost of $6,129 per replacement (2000 dollars), or 20% less than SCE's requested unit cost. TURN's proposal would result in disallowances of $14.454 million for 2002 and $15.264 million for 2003, or a total of $29.718 million. As an alternative to its proposed 20% reduction, TURN submits that SCE's forecast for wood pole replacements should be reduced by at least 16%.

TURN's analysis in support of its conclusion that SCE's pole replacement costs are unreasonably high is summarized below:

- SCE's forecast unit replacement cost for 2002 is $8,036, a figure derived by escalating the SCE forecast of $7,661 in 2000. Recorded data for 2002 show that the actual unit cost was $6,719 (Exhibit 384, weighted average), or 16.4% less than SCE's forecast. TURN submits that, at a minimum, SCE's own data substantiate the need for at least a 16% reduction in unit costs to $6,405 in year 2000 dollars.
- In the 1995 GRC, SCE used $2,400 (in 1992 dollars) as its unit replacement cost. Escalating this value by a non-labor escalation factor, the unit pole replacement cost in 2000 would be $2,916. Using the Handy-Whitman index for distribution poles in the Pacific region as an escalation factor results in a 2000 unit cost of $3,017. According to SCE, accounting changes adopted since the 1995 GRC require that indirect costs be added to the estimate used in that proceeding to yield a comparable value, and the comparable cost reflected in the 1995 GRC was $5,360 in 1992 dollars. TURN acknowledges the accounting change, but contends that this data still supports its primary recommendation because, according to TURN, a 1992 unit cost of $5,360 is equivalent to a cost of approximately $6,511 (2000 dollars).
- TURN contends that while both the 1995 GRC data and the 2002 recorded costs support a unit replacement cost between $6,400 and $6,500, a lower unit cost estimate of $6,129 is warranted due to anticipated cost savings. According to TURN, SCE's Work Management System (WMS) will reduce costs of field crew construction and maintenance. In addition, TURN expects a decrease in unit costs due to economies of scale, since SCE has doubled the number of annual pole replacements to over 10,000.
- In its 2004 GRC, PG&E stated that its unit replacement costs, before deducting the joint revenue credit, would be $6,724 in 2001

(nominal dollars), approximately 14% less than SCE's unit cost forecast of $7,850 (nominal) for 2001.

***Discussion***

TURN's conclusion that recorded 2002 unit costs were 16.4% below SCE's forecast for that year is not demonstrably based on a comparison of equivalent cost figures (i.e., an "apples to apples" comparison). In particular, the data upon which TURN relies to draw this conclusion do not appear to include adjustments for joint poles and other items that may be necessary to make a valid comparison of SCE's forecast and recorded costs for 2002.[39] Thus, while the cost figures in Exhibit 384 may cast some doubt on the validity of SCE's forecast, in light of the comparability problem they do not provide a sufficient evidentiary basis for adopting a unit cost forecast of 16% below SCE's forecast.

TURN's conclusion that SCE's forecast pole replacement costs are excessive compared to the costs underlying the 1995 GRC relies upon on data from 1992, stated in 1992 dollars. SCE draws a different conclusion from the same data. Depending on the escalation method used, the year 2000 unit cost estimates (excluding additional work items) range from $6,511 (TURN) to $7,155 (SCE). Because TURN used a non-labor escalator and SCE used a labor escalator, but the underlying cost includes both labor and non-labor components, we believe the more reliable conclusion to be drawn from the 1992 data is that the reasonable unit replacement cost falls between these two estimates. In short, with respect to data from the 1995 GRC, SCE and TURN have cast doubt on each other's recommendations for pole costs in this GRC.

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[39] We note that unit cost data in Exhibit 356 required joint pole and "repair item" adjustments in order to develop a valid comparison of SCE's and PG&E's costs.

With respect to the comparison of SCE's and PG&E's unit costs, the evidence shows that what are loosely termed urban versus rural conditions can significantly impact pole replacement costs. A pole that is located in a congested urban setting (e.g., surrounded by buildings or structures that make access difficult) will be more costly to replace than a pole that is located in an open rural environment where construction tends to be simpler, there is less equipment on the poles, and there are few problems with accessing structures. However, SCE's efforts to show that its rural-urban distribution of pole installations relative to that of PG&E explains most of the difference in the two companies' unit costs are neither convincing nor persuasive. SCE's evidentiary showing on this point can be accorded little weight. Accordingly, accepting SCE's estimated adjustment for "additional repair items" of $600 to arrive at a unit cost that is most comparable to PG&E's, the evidence shows that SCE's forecast cost of $7,061 ($7,661 less $600) is $526 greater than PG&E's forecast cost of $6,535.

We conclude that SCE has not sustained its burden of proving that a per unit pole replacement cost of $7,661 is reasonable. At the same time, there are enough problems with the evidence underlying TURN's proposed disallowance of 20%, and its alternative disallowance of 16%, to prompt us to reject those proposals as well.

Taking into account the potential for savings from economies of scale associated with a substantial increase in the size of the pole replacement program, it is reasonable to reduce SCE's authorized per unit cost to conform to PG&E's forecast cost. Accordingly, we reduce SCE's unit replacement cost of $7,661 by $526, and adopt a unit replacement cost of $7,135. This represents a reduction of 6.87% from SCE's requested capital expenditures of $72.315 million in 2002 and $76.509 million in 2003, or disallowances of $4.968 million for 2002 and $5.256 million for 2003 ($10.224 million for both years). This disallowance is in addition to the $3.447 million disallowance we have adopted in recognition of SCE's failure to perform timely intrusive inspections. (*See* Section 4.3.4.)

## 4.5. T&D O&M Expenses

### 4.5.1. ORA's Proposals

We have previously addressed TURN's recommendation to disallow approximately $1.7 million for intrusive pole inspection costs, adopting instead a reduction of $1.443 million. (*See* Section 4.3.4.) In this section, we address ORA's proposed reductions to SCE's T&D O&M forecast of approximately $7.6 million.

SCE largely relied on a budget-based approach to forecast O&M expenses for its T&D system. While accepting SCE's forecasts for several FERC accounts, ORA included the use of 2001 recorded FERC account data to arrive at its O&M forecasts for FERC Accounts 568, 571, 591, 594, and 598. For Account 582, ORA used a five-year average of data from 1996 to 2000.

***Discussion***

ORA's O&M recommendations that are based on the use of 2001 FERC account data are inconsistent with the intent of the Commission's Rate Case Plan, which provides for the use of a five-year recorded period (1996-2000 in this GRC). Moreover, the recorded FERC Form 1 data for 2001 are unadjusted, and therefore are not consistent with adjusted data for the 1996 to 2000 period that represents the base record period in this GRC. We note that SCE was under no obligation to provide ORA with adjusted FERC account data for 2001. In any event, even if it were otherwise appropriate to use FERC account data for 2001, the unusual conditions associated with the company's financial crisis render that year's recorded data less reliable for forecasting test year expenses, as the

Commission acknowledged in D.02-04-055. Accordingly, ORA's proposals for FERC Accounts 568, 571, 591, 594, and 598 will not be accepted.

ORA has also raised concerns about the significant rise in costs in FERC Account 582 (Distribution Station Expense), in which SCE records costs for dispatching distribution operations and field operations crews, processing switching programs, directing switching, monitoring circuit loading, and responding to circuit interruptions, equipment trouble, and customer inquiries. SCE's forecast of $11.918 million for this account is based on recorded expenditures for the year 2000. SCE claims that averaging is inappropriate for this account, referring to vacant operator positions that must be filled and expenses for retention bonuses. We find that this evidence does not support the rejection of averaging for this account, and therefore adopt ORA's five-year average forecast of $10.014 million. This represents a disallowance of $1.904 million for Account 582.

#### 4.5.2. Jurisdictional Separation

Resolution E-3712 directed SCE to verify in its next GRC that certain transmission O&M costs included with its 1998 PBR operating expenses were distribution related and reasonable. Resolutions E-3771 and E-3772 made similar requests with regard to 1999 and 2000 transmission O&M expenses. SCE presented testimony in this GRC in response to these directives. No other party addressed this issue.

***Discussion***

SCE has fulfilled the relevant requirements of Resolutions E-3712, E-3771, and E-3772, and has demonstrated that certain subtransmission expenses discussed therein are subject to our jurisdiction and have been properly included in PBR revenue requirements.

### 4.6. Line and Service Extension Rules

Line and service extension costs associated with connecting new customers are categorized as distribution capital investments and recorded to plant in service. When an applicant selects SCE to perform line extension construction work, SCE estimates the total construction cost and calculates an allowance based on the revenues expected from the project load. SCE charges the applicant the difference between the allowance and the estimated costs.

TURN takes the position that ratepayer liability should never exceed the amount of the allowance, and that either the applicant or SCE should be liable for any cost overruns. TURN recommends that the Commission adopt the ratemaking principle that the revenue-based allowance is a cap to ratepayer liability for line extension project costs. TURN also requests that the Commission adopt rates subject to refund, order SCE to provide the necessary data to evaluate historical cost overruns, and subsequently modify rates based on a review of the data. TURN contends that, at a minimum, the Commission should order SCE to properly track its line extension costs going forward to allow an evaluation of cost overruns.

***Discussion***

The evidence does not support the claim that SCE has pursued practices in the administration of the line and service extension rules that are in contravention of its tariffs or Commission orders. No basis exists in this GRC for a ratemaking disallowance related to the reasonableness of SCE's T&D capital additions associated with line and distribution extensions.

In D.94-12-026 (58 CPUC 2d 1), the Commission modified the gas and electric utilities' main and distribution extension rules so that the allowances would be based on the expected revenues from the load served by the extension.

In D.97-12-098 (77 CPUC 2d 785), the Commission again modified the line and service extension rules and practices for gas and electric utilities to reduce the amounts by which ratepayers subsidize the costs caused by new ratepayers requiring new line and service extensions. The Commission noted in D.97-12-098 that the adopted modifications would result in more uniform and consistent practices among the utilities.

TURN is now asking that a new rule be adopted, applicable only to SCE, to further advance the principle addressed by D.97-12-098, i.e., that subsidies by existing ratepayers to newly connected ratepayers should be reduced. We remain committed to the promotion of more uniform and consistent practices among the gas and electric utilities, and are not persuaded that it is necessary or appropriate to revise SCE's extension rules at this time by the adoption of a cap on ratepayer funding responsibility.

TURN's underlying concern is that without a cap, the utility lacks adequate incentives to control construction costs, and that ratepayers bear the risk of actual job costs being greater or less than estimated costs. The only SCE evidence on this point is the opinion of an SCE witness that making accurate construction cost estimates is a utility responsibility, and that cost overruns and cost underruns will balance out over the long run; and a compilation of a small sample of jobs showing an aggregate 5% overrun. However, SCE failed to provide documentation to support this opinion, despite having been asked to do so in a data request, and the sample compilation is not demonstrably reliable.

We place SCE on notice that, in the event that the Commission further considers the line and service extension rules, SCE cannot escape its responsibility to provide the Commission and parties documentation necessary to support such assertions. Based upon SCE's discovery responses in this proceeding, it appears that the company may need to modify its record keeping so that it is able to keep track of the data in a manner that would allow calculation of total line extension job costs recorded to rate base, versus total estimated costs and total allowances for the same work orders.

## 4.7. Electric Transportation

### 4.7.1. Introduction

SCE proposes to continue its Electric Transportation (ET) Program activities in the 2003 GRC cycle. SCE states that its ET program allows it to implement its electro-drive programs and activities and continues its ability to comply with the federal Energy Policy Act of 1992 (Pub. L. 102-486, codified in 42 U.S.C.; hereinafter, EPAct) as well as state and local goals and programs. SCE forecasts $6 million in expenses (FERC Account 588 – Miscellaneous Distribution Expenses) for the test year, consisting of $1.875 million for labor and $4.125 million for non-labor. ORA and Aglet have proposed reductions to SCE's forecast, as discussed below.

Certain issues related to the Low Emission Vehicle (LEV) program were addressed in the consolidated LEV proceeding (A.02-03-048 et al.). By ruling entered in the LEV proceeding on June 26, 2002, later affirmed by the Commission in D.02-12-056, the Assigned Commissioner determined that certain "discretionary" utility activities would be addressed in the LEV proceeding and that "mandatory" activities listed below would be addressed in the utilities' respective GRC's:

- Acquisition of alternative fuel use fleet vehicles pursuant to EPAct.
- Operation and maintenance costs associated with use of alternative fuel use fleet vehicles and associated infrastructure.
- Infrastructure (fueling facilities and related equipment) needed to support alternative fuel use fleet vehicles.

- Employee training and instruction necessary for the use of alternative fuel use fleet vehicles.
- Accounting for the costs of these mandatory activities.

#### 4.7.2. ORA's Recommendations

ORA recommends that discretionary LEV expenses of $677,000 not be considered in this GRC. ORA also recommends a disallowance of $463,000 of ET costs based on a belief that these costs were under review in the LEV proceeding.

***Discussion***

While discretionary LEV activities were reviewed in the LEV proceeding, the result of the review (as applicable to SCE) will be reflected in the revenue requirement adopted in this GRC. Thus, of necessity, discretionary LEV activities are "considered" herein. Moreover, a disallowance of $677,000 of discretionary LEV program expense is excessive given that the discretionary program costs under review in the LEV proceeding were $303,600. Our intent is to include in the adopted GRC revenue requirement the discretionary funding approved in the LEV proceeding.

ORA's proposed disallowance of $463,000 relates to electric trolley and high-speed electric rail, not LEVs. Because they relate to mass transportation, these programs were not part of the LEV proceeding. These are on-going ET program costs and were authorized in SCE's 1995 GRC.

#### 4.7.3. Aglet's Recommendations

Aglet takes issue with the non-labor component of SCE's budget-based forecast of $4.125 million. Using recorded costs for 2000 as the basis for its forecast, Aglet recommends instead a forecast of $2.257 million. This represents a proposed disallowance of $1.868 million.

Nominally a dispute over forecasting methodology (budget-based v. last year recorded), this dispute largely pertains to the estimated costs of compliance with the EPAct requirement that utilities to purchase Alternative Fueled Vehicles (AFVs). SCE’s fleet contains approximately 2,550 Light Duty Vehicles (LDVs) covered by the EPAct mandate, and in a normal year SCE may replace as many as 500 LDVs. SCE’s GRC forecast assumes that it will purchase 500 LDVs in 2003, triggering an EPAct requirement to purchase 450 AFVs. However, SCE budgeted to acquire 200 AFVs, assuming that the rest would be made up with credits authorized under EPAct.

Aglet faults SCE for assuming that compliance with EPAct requires the purchase of electric vehicles exclusively. While EPAct allows compliance through use of nine different types of alternative fuels, SCE has not even considered pursuing cost estimates for any fuel type except electricity. SCE believes that its commitment to electric vehicles is reasonable because it provides electricity, not natural gas or propane, and it needs to "be smart" about electric vehicle technologies in order to provide customers with related information. SCE opposes compliance through use of natural gas or propane vehicles because it does not have the necessary infrastructure, and use of those technologies would ignore the investments made to support electric vehicles.

Aglet does not object to SCE's continued assessment of electric transportation technologies, but argues there is no convincing evidence that SCE must purchase 450 electric vehicles or compliance credits every year in order to "be smart." Aglet believes that a better strategy would be to purchase enough electric vehicles to perform reasonable technology studies and maintain an electric vehicle presence in SCE's fleet, and to pursue remaining EPAct compliance in ways that minimize ratepayer costs.

***Discussion***

SCE asserts that purchase of propane or natural gas vehicles would cause significant costs of adding the necessary refueling infrastructure. However, having not studied this question seriously it at all, SCE is in no position to make such assertions.

SCE's also relies on Commission findings made in 1995 to support its commitment to the exclusive use of electric vehicles. However, while the 1995 Commission found it "sensible and appropriate" for electric utilities to use electric vehicles to meet their purchase obligations under federal law while gaining an understanding of any safety and reliability implications from their use (D.95-11-035; 62 CPUC 2d 395, 456), it did not prescribe exclusive use of electric vehicles. SCE cannot reasonably rely on this finding to simply ignore the potential for cost savings that may be realized with the use of other AFV technologies that meet EPAct requirements. In the very decision that SCE relies on to explain its exclusive commitment to electric vehicles, the Commission found that utilities are under no obligation to buy either natural gas or electric vehicles. (*Id.*)

There is no legal obligation that SCE must buy electric vehicles, let alone electric vehicles exclusively, or that the Commission must approve cost recovery for alternative fuel vehicle programs that do not benefit ratepayers. At the same time, SCE has not justified exclusive use of electric AFVs on the basis of its infrastructure argument. Thus, SCE has not met its burden to show how ratepayers would benefit from purchase of 450 electric vehicles or equivalent credits when purchase of less expensive vehicles would satisfy EPAct. We conclude that SCE has not justified its budget-based forecast.

SCE has put forth evidence to show that use of the last recorded year would understate its funding requirements for 2003. In 2000, automakers had limited production of electric vehicles, and SCE was only able to acquire 31 new electric vehicles. SCE therefore had to use a large part of its available EPAct credits to meet its 2000 EPAct requirements. SCE states that these credits will not be available in 2003. In addition, the EPAct AFV requirement was 70% of LDV purchases in 2000, whereas it is 90% in 2003. The problem with this evidence is that, again, SCE has failed to show whether it could have met EPAct requirements in 2000 with non-electric AFV purchases at lower cost. If anything, the fact that only 31 vehicles were available for purchase in 2000 should have been a wake-up call to SCE that its commitment to the exclusive use of electric vehicles required reevaluation. Thus, we cannot rule out the possibility that even the recorded year costs are excessive. Nevertheless, we will adopt Aglet's proposal to use the last recorded year, as it is the most reliable forecasting method supported by the totality of this record.

## 5. Customer Service

### 5.1. Introduction

SCE's Customer Service Business Unit (CSBU) has 2,900 employees. Among its functions are meter reading; billing and payment services; call centers for inquiries regarding service establishment, billing and payment arrangements, tariff matters, conservation, load curtailment programs, and other issues; field services such as turn-ons, turn-offs, billing inquiries, investigations of meter accuracy and energy theft, and meter replacements; credit functions; Electric Service Provider (ESP) support; account management for non-residential customers; customer satisfaction research; responding to industry restructuring inquiries; and resolution of complaints.

Section 5 of this decision addresses SCE's requested O&M expenses for customer service functions, proposals for service fees, and CSBU related capital requirements. Also addressed are proposals regarding service guarantees and other customer service issues that do not have direct revenue requirement impacts in this GRC, including ORA's proposals regarding Authorized Payment Agencies (APAs) and LA County's proposals regarding metering, billing, and other customer matters.

## 5.2. O&M Expenses and Related Issues

### 5.2.1. Overview

SCE estimates that customer services will require O&M funding of $184.5 million (2000 dollars, excludes uncollectible expenses) for test year 2003. This request consists of $150.7 million for Customer Service Operations (FERC Accounts 901-905) and $33.8 million for the Customer Service and Information (CS&I) function, which addresses what SCE describes as the more complex needs of primarily non-residential customers (FERC Accounts 907, 908, and 916).

Noting that its requested funding level is $20.1 million greater than the 2000 recorded / adjusted level of $164.4 million, SCE's Senior Vice-President of Customer Service identified the following factors underlying its request that have caused the increase: (1) direct access costs would be recovered as an O&M expense for the first time in 2003; (2) Public Goods Charge (PGC) funding would no longer cover SCE's technology centers, the pump test program, and customer load control programs; (3) customer growth requires greater expenditures in almost all CSBU areas; (4) increased postage costs; and (5) regulatory mandates such as Real-Time Energy Metering (RTEM), new tiered-rate structures, and rotating outage notification procedures.

### 5.2.2. Customer Service Operations

#### 5.2.2.1. Forecast Method

SCE used multi-year averages to forecast expenses for four of 12 Customer Service Operations accounts or sub-accounts, and otherwise used the base-year method. As a matter of consistency, ORA advocates the use of the base-year amount where possible. Taking issue with SCE with respect to Account 901 (Business Unit Management Support) and Account 903.200 (Credit Services), ORA recommends rejection of the averaging methodology for those two accounts. SCE used three-year averages to estimate expenses for these accounts to avoid year-to-year variations and/or anomalies that may be present in the base year recorded costs. ORA recommends using the last year recorded method to forecast costs in these accounts because ORA finds that there has been very little variation from year to year in the 1998–2000 period. ORA's approach results in a proposed disallowance of $283,000.

***Discussion***

Use of the last year's recorded values would be appropriate if there were stronger evidence supporting the proposition that those values are more predictive of test year expenses than those for the other years. Here, if anything, the opposite is the case. For Account 901, recorded expenditures in 2000 were the lowest of the last three years due primarily to cash conservation measures implemented in the fourth quarter of 2000. For Account 903.200, SCE expects future collection costs to increase due to the less stable economy and higher electric rates. While this expectation of increasing collection costs is not fully supported by independent evidence, it is nevertheless based on professional judgment and is more reasonable than the unsupported assumption that year

2000 expenses are more predictive than the average of the years 1998-2000. SCE's averaging approach yields the more reliable forecast and is therefore approved.

ORA proposed a reduction to postage costs of $100,000 to reflect reduced postage rates proposed by the Postal Service. SCE generally agrees to the reduction, but contends that it should be corrected to $97,000. ORA agrees with the corrected reduction of $97,000, which we adopt.

#### 5.2.2.2. Uncollectible Factor

SCE used the five-year average of uncollectible factors (1996-2000) of 0.319% for its test year uncollectible factor. SCE added to this factor 0.007% to reflect additional uncollectibles associated with its proposed residential late payment charge (LPC) and increased Field Assignment Charge (discussed below), for a total factor of 0.326%.

ORA proposes using the last recorded year's factor of 0.311% to estimate future uncollectible expenses. This methodological difference yields an O&M expense difference of $539,000. Aglet proposes using SCE's recorded 1995 uncollectible factor of 0.264%, yielding a difference of $1.648 million.

The parties agree that to the extent that SCE's proposed LPC and its proposed increase to the Field Assignment Charge are rejected, the 0.007% adder associated with those charges should be adjusted or eliminated accordingly.

***Discussion***

SCE's five-year average (0.319%) is based on the historical uncollectible data set forth in the following table.

**Uncollectible Factors**

| 1996 | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|
| 0.283% | 0.315% | 0.340% | 0.348% | 0.311% |

ORA disagreed with SCE's use of a five-year average because, using a process known as POSID, SCE has improved its assessment of the creditworthiness of new service applicants. ORA believed that the use of older data in a five-year average would exclude likely reductions in uncollectibles due to the new procedures. However, the five-year average already includes the effects of the POSID process, which was implemented prior to 1997. ORA is also concerned that SCE's uncollectibles rate rose from 1996 to 1999 even as unemployment and poverty rates in SCE's service territory declined. ORA faults SCE for failing to explained this increase.[40]

We take a different view regarding this data, i.e., unemployment and poverty rates simply may not be as reliable as predictors of SCE's uncollectible factor as SCE and the other parties seem to assume. We are also not persuaded that corporate bankruptcies are as explanatory as SCE assumes. We are left with the data shown in the table above and non-compelling explanations for any trends that may be occurring. In the absence of more compelling evidence that the uncollectible rate from any single year (whether 1995 as Aglet recommends or 2000 as ORA recommends) is more predictive than an average of several years, SCE's proposal to use a five-year average is more reasonable and will be adopted. As we are adopting SCE's proposed LPC, but not its proposed Field Assignment Charge, we adopt an adder of 0.005% instead of 0.007%.

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[40] Table III-1 in Exhibit 37 shows that from 1996 to 2000 unemployment in SCE's service territory declined from 7.6% to 4.5% and from 1996 to 1999 poverty declined from 18.8% to 14.9%

#### 5.2.2.3. Authorized Payment Agencies (APAs)

The majority of Edison's customers (72%) pay their bills by mail. Another 20.4% of customers pay their bills in person at SCE's Local Business Offices (LBOs) or, increasingly, at one of SCE's 369 APAs. These are independent businesses that provide bill payment services for SCE in exchange for a transaction fee.

ORA found that some customers who pay their bills in person have complained about poor service. ORA recommends that SCE improve APA services and expand the APA network where needed. Specifically, ORA recommends that APAs be:

- Located a reasonable distance from the customer's home or office, recognizing the differences among urban, suburban and rural locations.
- Located in retail centers that provide parking, access via public transportation, safety and convenience.
- Located in businesses that are clean and pleasant, and that process payments professionally, efficiently and courteously.
- Located in businesses that process payments from Edison as well as other companies to provide one-stop service for customers.
- Located in businesses that are open for business six days per week or more and open extended hours each day (e.g., 8:00 a.m. to 9:00 p.m.).

In addition, ORA recommends that SCE undertake an education program to migrate customers away from in-person payments to lower cost payment options. Finally, ORA recommends that SCE evaluate the feasibility of replacing or supplementing APAs and LBOs with unmanned payment processing stations.

SCE objects to ORA's characterization of LBO and APA customer issues and believes that its customers are reasonably satisfied with the bill payment options offered by the company.

***Discussion***

While it contends that SCE should improve the level of service provided to customers who use APAs and LBOs to pay their bills, ORA agrees that, overall, SCE is performing satisfactorily in this area. Moreover, despite their differences regarding the nature and extent of customer dissatisfaction and how to interpret customer satisfaction surveys and focus group results, there appears to be little actual disagreement between SCE and ORA regarding ORA's specific recommendations for the APA program. In effect, except for ORA's recommendation to study the feasibility of unmanned payment processing stations, to which it did not respond, SCE accepts those recommendations. SCE has already established criteria for locating and establishing APAs that essentially include ORA's recommended criteria regarding accessibility to transportation, convenience, etc. We endorse these criteria, and expect SCE to continue to ensure that they are implemented. Similarly, SCE in effect agrees with ORA's recommendation for educating customers on the availability of lower cost payment options by noting that it has undertaken such an information campaign.

We do not find it necessary to undertake additional regulatory efforts at this time to improve SCE's APA program. We do find ORA's recommendation for an evaluation of the feasibility of replacing or supplementing the APA/LBO network with automated payment processing intriguing. If cost-effective, this payment option may provide a higher level of customer service and flexibility. SCE should report on its efforts to evaluate the feasibility of such options in its next GRC filing.

#### 5.2.2.4. Internet Site Maintenance

The volume of SCE's Internet communications has been expanding in recent years. Within Account 901, SCE requests $681,000 in additional expenses for Internet content maintenance, including $310,000 for personnel and $321,000 for technical development.

Aglet is concerned that SCE made little or no effort to determine the effect of growing Internet use on costs for other forms of communication. SCE's website has been open for public use since January 1995, and it allows customers to establish new service, and transfer or close service through on-line transactions. Aglet believes that those who use the Internet to gain information from or about SCE will, to some extent, forego the use of other forms of communications such as telephone calls to SCE's customer service center and written communications. Aglet notes that the volume of customer calls has been declining. Aglet witness Weil has used SCE's website to review or download tariff sheets and financial information, which would otherwise have required him to write or call SCE. According to ORA witness Kinser, SCE customers have indicated that Internet use is more convenient than telephone use or visiting utility offices.

Aglet contends that in requesting an additional $681,000 in ratepayer funding to maintain and operate its website, SCE has not met its burden of showing that improved Internet capability will not affect other customer information revenue requirements. Aglet also contends that SCE has not shown that the new Internet expenses will be cost-effective. Aglet therefore recommends a disallowance of 50% of the new program expenses, or $340,000, to compensate ratepayers for reductions in other customer communications costs caused by the Internet expansion, and for the uncertainty of program benefits.

SCE asserts that increased Internet expenditures will become cost effective in future years as more customers use the Internet.

***Discussion***

SCE's contention that cost savings benefits from its investment in its Internet capabilities will not be realized until a future rate case lacks merit. The evidence shows that customers now have the ability to use the internet to interact with SCE, and that to some extent they do so instead of using other forms of communication. Accordingly, and since SCE has not adequately studied the issue, Aglet's recommended disallowance of $340,000 is reasonable under the circumstances and will therefore be adopted.

#### 5.2.2.5. Direct Access Costs

Pursuant to D.99-09-064, SCE's customer service O&M forecast includes a forecast of direct access customer costs. SCE's forecast of $3.799 million is based on the assumption that the number of direct access customers will range from 30,000 to 70,000. This represents a reduction from the recorded direct access costs of $7.331 million in 2000 and $4.474 million in 2001, but an increase over the recorded cost of $3.690 million in 2002.

TURN contends that because direct access has been closed to new customers since September 2001, and SCE serves 42,521 direct access customers, or 40% less than the maximum number assumed by SCE, there is no rationale for an increase in direct access costs in 2003. TURN submits that, barring new legislation, the only foreseeable likelihood is that the number of direct access customers will decrease. TURN therefore recommends one-way balancing account treatment for SCE's entire $3.8 million estimate of direct access costs. In the alternative, TURN recommends a 20% reduction to SCE's estimate.

***Discussion***

SCE's request rests on the proposition that its direct access related customer expenses are essentially fixed at $3.8 million if the number of direct access customers remains within the 30,000 to 70,000 range. SCE states that these are ongoing costs that have stabilized over the last two years. While we accept SCE's showing regarding the relatively fixed nature of these costs, SCE has not adequately demonstrated why its test year expense would be higher than the 2002 level. We will adopt a forecast of $3.690 million based on the 2002 recorded level. TURN's request for one-way balancing account treatment is not justified, as it is just as conceivable that SCE's estimate is too low as it is too high.

### 5.2.3. Customer Service & Information

#### 5.2.3.1. Public Goods Charge Funding

SCE has two technology centers that provide customers with information on electromagnetic fields, metering, energy management, energy efficiency, and environmental solutions. These are the Customer Technology Application Center located in Irwindale and the Agricultural Technology Application Center located in Tulare. SCE also has a pump test program that serves agricultural customers, water agencies, municipalities, and other pumping customers. SCE has funded these activities in whole (pump test) or in part (technology centers) with Public Goods Charge (PGC) money.

With an expectation that PCG funding would be eliminated, SCE proposed to add $2.531 million in O&M funding for these activities. In 2000, SCE recorded $1.513 million in O&M funding and $2.45 million in PGC funding for the two technology centers. For the 2003 test year, SCE seeks to add an additional $1.272 million for a total O&M forecast of $2.785 million for the technology centers. In 2000, the pump test program was funded by $1.27 million in PGC money. For 2003, SCE seeks to fund the pump test program with $1.259 million in O&M money.

ORA opposes SCE's request for an additional $2.531 million in O&M funding for these activities. ORA takes the position that with the enactment of Assembly Bill 995 in 2000 (Stats. 2000, Chapter 1051), PGC funding will be available through the year 2011.

***Discussion***

This dispute does not address the reasonableness or effectiveness of the technology centers or the pump test program. It pertains to the appropriate funding mechanism, i.e., whether these functions should now be fully funded through base rates by their inclusion in O&M expenses, or whether they should remain part of the PGC funding process. Apparently acknowledging that PGC funding will not be eliminated any time soon, SCE nevertheless believes that some of the functions provide basic customer care, and it prefers the more stable funding of the GRC mechanism to the less certain funding of the PCG process. However, SCE's preference for more stable funding for the technology centers and the pump test program does not justify a shift in funding at this time, and SCE's basic customer care argument is unconvincing. Moreover, as ORA points out, SCE has not adequately explained why these of all programs that are now covered by the PGC should be singled out for O&M funding. As to SCE's concern about the future administration of these programs, we note that if, in the future, the Commission considers the selection of other administrators for these functions, SCE will have an opportunity to participate in relevant proceedings. At best, SCE's proposal is premature. Accordingly, SCE's request to fund the technology centers and the pump test program through an O&M allowance in this GRC is denied.

#### 5.2.3.2. Air Conditioner Cycling Programs

Established in 1983, the Air Conditioner Cycling Program provides load relief during periods of high demand in return for a rate discount. D.01-04-006 reopened the program to new participants and ordered program enhancements. SCE estimates that participation will increase to 170,000 customers by the end of the test year. The majority of the additional customers will require the installation of cycling devices, and SCE's O&M request includes material costs of $3 million (Account 908) for their acquisition.

ORA wishes to encourage this program but it does not believe that SCE's projected enrollment growth is borne out by the data. Participation was 114,002 in October 2001 and it dropped to 110,624 by July 2002. ORA recommends that SCE's annual estimate be reduced from $3 million for 19,900 cycling devices per year to $1 million

SCE responds that a $2 million disallowance for devices will limit it to installing or replacing only about 6,700 devices per year. SCE contends that this is inadequate to meet expected demand and replace existing defective devices in the coming years. While SCE believes that ORA has underestimated the potential number of enrollees, it acknowledges ORA's concern, and therefore proposes to establish a one-way balancing account that would reconcile differences in the actual cost incurred for new or replace air conditioning cycling devices and the allowed revenue requirement in this case.

***Discussion***

Forecasting enrollment levels in this program is particularly difficult at this time. On the one hand, ORA's estimate of annual growth of 5,000 customers per year reflects the first year after the cycling programs were authorized, which may not be an accurate reflection of test year activity since the cycling programs had been scheduled to terminate on December 31, 2002 and potential customers were just coming off a year of rotating outages. Further, SCE has stepped up its marketing activities this winter season and it expects that the current rate of enrollment will increase in 2003 and beyond. On the other hand, SCE's expectations notwithstanding, the actual enrollment data do not support a need for 19,900 new cycling devices in 2003.

In order to promote this potentially valuable load control program, we will approve SCE's forecast subject to a one-way balancing account as proposed by SCE. In addition to maximizing the potential benefits of this program, this approach will ensure that ratepayers provide funding only for cycling devices acquired and installed by SCE.

#### 5.2.3.3. Load Control Programs

TURN initially recommended that forecast costs for all SCE's load-control programs receive balancing account treatment, not just the air conditioning cycling program. SCE opposed this proposal, and TURN did not address it on brief.

***Discussion***

In contrast to the costs for air conditioning cycling devices, administrative costs for the cycling programs and for all the other load-control programs are relatively stable. A large change in customer participation numbers has only a modest impact on administrative costs. We find insufficient justification for balancing account treatment for load-control programs except for air conditioning cycling devices, and therefore deny TURN's recommendation.

#### 5.2.3.4. Economic and Business Development Costs

Section 740.4 directs the Commission to authorize utilities to engage in programs to encourage economic development (subdivision (a)) and to allow recovery of reasonable expenses for such programs to the extent of ratepayer benefit (subdivision (b)). Subdivision (h) of Section 740.4 states the Legislature's intent that rate recovery shall be allowed "to the extent the utility incurring or proposing to incur those expenses and rate discounts demonstrates that the ratepayers of the public utility will derive a benefit from those programs."

SCE's Director of the Commercial and Commodities Segment in the Major Customer Division of the CSBU testified that current economic conditions in California "reinforce the fundamental need for the State of California to sustain an integrated economic development function and a vital role for SCE to maintain active and aggressive participation in that process." (Exhibit 39, p. 64.) As a consequence, SCE requests $2.514 million in O&M funding (Account 908, $1.467 million labor and $1.047 million non-labor) for Economic and Business Development (E&BD) activities. SCE states that these activities serve to retain, expand, and attract business facilities and operations that would otherwise locate outside of California. SCE's witness testified that the primary customer target class is manufacturers, and that while the program can help all customers, SCE has "more likelihood of helping a large manufacturing customer." (Tr. V. 17, p. 1228.) SCE takes the position that all customer rates are reduced by maintaining and/or increasing revenues to cover fixed costs.

The Commission has applied the Rate Impact Measure (RIM) test for assessing the cost-effectiveness of demand-side management (DSM) programs. It has described the RIM test as follows:

> The RIM test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the

> program. The benefits calculated in the RIM test are the savings from avoided supply costs (to which non-price factors would apply). The costs for this test are the program costs incurred by the utility, the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any period when load has been increased." (D.95-06-016, 60 CPUC 2d 265, 293, footnote 5.)

Adapting the RIM test to an analysis of E&BD costs and benefits, SCE analyzed the difference between revenues and marginal costs for the kilowatt-hours affected by the E&BD program. SCE determined that the E&BD program yields a benefit/cost ratio of 1.26 using rates in effect during 2000 and assuming continuation of the PBR mechanism. SCE also calculated a RIM test benefit/cost ratio of 2.11 under the assumption of a revenue adjustment balancing account ratemaking mechanism. SCE contends that this provides the necessary justification for its E&BD funding request.

Aglet contends that SCE incorrectly applied the RIM test and failed to demonstrate ratepayer benefits of E&BD activities. Aglet proposes to eliminate all ratepayer funding for this function, resulting in a disallowance of $2.514 million. Aglet's concerns with SCE's RIM test analysis include the following:

- Aglet contends that SCE failed to measure "what happens to customer bills or rates due to changes in utility revenues and operating costs" caused by the E&BD program. In its initial showing, SCE calculated only the effects of proposed E&BD activities on electric distribution, transmission, nuclear decommissioning and public purpose program costs and revenues, and excluded generation related revenues and costs from the RIM test. Aglet contends that this exclusion is internally inconsistent and wrong. Aglet claims that SCE ignored the effects of E&BD efforts on generation and procurement needs, and that SCE does not know how future generation costs would affect the cost-effectiveness E&BD activities.

- Rebutting Aglet's position regarding the exclusion of generation from the RIM test, SCE provided RIM test results from a DSM report that included "Commission-specified avoided generation costs." Based on this DSM report, SCE asserts that the E&BD programs reduce rates because benefit/cost ratios exceeded one. Aglet responds that those avoided generation costs are not included in the record, and they appear to have been based on forecasts made prior to the years 1995-2001. Aglet is skeptical of their applicability here, as SCE's actual avoided costs during the 2000-2001 financial crisis were much higher than average rates. Aglet notes that SCE has presented no information on test year 2003 incremental generation and procurement costs.
- Aglet contends that SCE did not complete all of the necessary elements of the RIM test. Pursuant to D.95-06-016, SCE as the program proponent must also identify effects on core customers of programs that increase load in noncore markets and identify expected program benefits in terms of rate effects, resource planning effects, and other effects. Aglet submits that SCE has not shown how load increases caused by the E&BD program will affect overall customer rate levels or resource planning.
- If incremental supply costs are higher than average rates, then incremental load increases will raise average rates. SCE agrees that this principle applies to business expansion programs, but disputes Aglet's position that it also applies to business retention programs. Aglet responds that retention programs are equivalent to attraction programs if one uses the correct definition of incremental costs. Aglet submits that since incremental supply costs are likely higher than average costs, at least at times, there will almost certainly be periods where the load building resulting from E&BD activities will cause higher rates for SCE customers.
- Aglet contends that there is no evidentiary support for SCE's assumptions that program participants are influenced by the specific percentages upon which SCE relies. For example, there is no rigorous showing that up to 90% of increased loads installed by participants in SCE's programs has been or will be attributable to the programs.

***Discussion***

Pursuant to Section 740.4, we should approve the requested E&BD funding to the extent that SCE has demonstrated that ratepayers will benefit from the activities funded through the request. On the other hand, to the extent that SCE has failed to make such a demonstration, we must deny the funding request. As explained below, we find that SCE has failed to establish that its RIM test analysis provides a valid demonstration of ratepayer benefit, and, therefore, we are bound to deny its E&BD funding request.

As a preliminary matter, we note that Aglet accepts SCE's position that the RIM test for DSM programs is an acceptable means of testing for ratepayer benefits of the E&BD program. We will therefore focus on the disputes over SCE's adaptation and implementation of the RIM test. Also, SCE points out that Aglet did not perform a RIM test calculation or recalculate the impact of Aglet's recommendations on the RIM test. However, the burden of proof rests with SCE to demonstrate the validity of its RIM test analysis. Aglet is not the proponent of SCE's E&BD funding, and it is not obligated to perform a RIM test.

The central dispute is whether generation-related costs and revenues should be included in the RIM test. SCE has contended they should not be included because of the changed role of the utility with respect to generation and the structure of the generation market in which generation-related costs are passed through to ratepayers.[41] That contention lacks merit. Consistent with the

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[41] SCE has equivocated on the inclusion of generation in the E&BD RIM test analysis. In rebuttal testimony, SCE states that "including generation costs in the RIM test analysis as recommended by Aglet is inappropriate." (Exhibit 297, p. 29.) During rebuttal hearings SCE testified that "essentially what we have done, Mr. Weil, is acknowledged that it may well be appropriate to include generation." (Tr. V.41, p. 3833.)

specification of the RIM test in D.95-06-016, the RIM test should measure what happens to total customer bills or rates due to changes in utility revenues and operating costs caused by the program.

By arguing for the exclusion of generation, SCE in effect is claiming that it is reasonable if ratepayers are worse off due to higher total rates as a result of their funding E&BD activities, as long as those activities lower a portion of their rates. That is neither reasonable nor consistent with the Commission's specification of the RIM test. Moreover, SCE's position is inconsistent, since it included transmission in its RIM test analysis even though this is not a transmission rate case. Generation (including procurement) costs and revenues should be included in the RIM test.

SCE's attempt to resurrect its RIM test analysis with DSM report data covering the years 1995 to 2001 in unconvincing. SCE has not demonstrated that "Commission-specified avoided generation costs" applicable to those years and reflected in the DSM report are appropriately applied to the test year analysis applicable in this GRC. In particular, SCE has not shown that market conditions beginning with the energy crisis of 2000 and legislative and regulatory responses are reflected. SCE also contends that generation costs do not have a significant effect on benefit/cost ratios in the RIM test analysis, but it has not demonstrated why that would be so, particularly if more current data reflecting those developments are used.

#### 5.2.3.5. LA County's Proposals

##### 5.2.3.5.1. Introduction

LA County has more than 2,500 separately metered accounts with SCE, making it the company's second-largest customer. It asks that the Commission require SCE to be more responsive to the needs of large, multi-account customers. Section 5.2.3.5 addresses three specific LA County requests.

#### 5.2.3.5.2. Billing and Consumption Data

LA County seeks to establish a mechanism to obtain metered consumption data for its time-of-use accounts and billing data for all of its accounts in a manner that would allow it to better manage its energy consumption and expenditures. Under the existing program offerings provided by SCE to large multi-account customers, it would have cost the County anywhere from $100,000 to $687,500 a month to obtain the information it needs in a useful format. This expense is not acceptable to the county.

SCE committed in this proceeding to provide the County with billing data through a modified version of SCE's Electronic Data Interchange (EDI) offering, which was previously only available to customers who were able to pay their bills electronically. Under this commitment, LA County will continue to be able to pay its bills by paper, and SCE will provide all of the bill information currently provided on the paper bill to a value added network (VAN) with whom the County will contract for the purpose of obtaining the information. SCE estimates that it will cost the County approximately 32 cents per month per bill to obtain the data. LA County will purchase the necessary hardware and software to convert the data into a format consistent with the energy management software the County has purchased. LA County welcomes and requests that the Commission endorse SCE's commitment to provide a modified EDI service through a VAN in addition to the paper billing SCE now provides.

***Discussion***

SCE's existing customer offerings to provide consumption data and billing data are not well suited to customers such as the County with many accounts.

SCE and LA County have worked cooperatively to achieve a solution that meets the County's needs and is workable for the utility. We endorse the results of their efforts, with the understanding that SCE will make the offer available to all similarly situated customers.

#### 5.2.3.5.3. Energy Efficiency Financing

SCE makes third-party financing available to customers for meters and other equipment, including energy efficiency equipment. LA County is concerned that SCE's financing program is not designed for local governments to use, and it notes that no municipality has taken advantage of it. Because financing is critical to the ability of local governments to invest in energy efficiency, the County requests that the Commission order SCE to modify its third party financing program for energy efficiency investments in a manner that will enable the participation of municipal governments.

***Discussion***

The record does not support an order directing SCE to make particular modifications to its third-party financing program at this time. However, SCE states that it is working with the County to better understand the County's borrowing limitations, and that it is fully prepared to work with the County and participating lenders to determine how the County's needs can be addressed through a third-party lending program. LA County has suggested that we order a workshop so that SCE can obtain the input it requires to tailor such a program to the needs of local governments. In light of SCE's stated willingness to work with the County, we direct SCE to convene a workshop as proposed by the County, not later than 90 days after the effective date of this decision. SCE should provide notice and an opportunity for municipalities in its service territory to participate. Our objective in making this directive is to explore whether and how SCE's third-party financing can be made effectively available to local governments so that they may more aggressively pursue cost effective DSM projects.

#### 5.2.3.5.4. Ratepayer Impact Analysis

LA County states that it is overwhelmed by the number of proceedings before this Commission that could significantly impact its energy budget. The County needs to constantly prioritize and allocate its resources in order to ensure that it participates in proceedings that have the greatest impact on the County as a ratepayer. The County requests that we order SCE to provide a free-standing, easily identifiable "ratepayer impact analysis" on its website in conjunction with any proposal made by SCE in a Commission proceeding that could increase rates for any single rate class by 5% or more. The County had initially requested that SCE provide additional information such as summaries of the positions of other parties, but has withdrawn those proposals.

SCE opposes this request, contending that such detailed information would be useful to only a small number of customers; that it already provides ongoing information to customers about regulatory, legislative, and marketplace developments; and that providing the information required by the County would require sizable staffing additions.

***Discussion***

Even though some ratepayers would undoubtedly benefit from a requirement that SCE provide a ratepayer impact analysis as recommended by the County, we must weigh the costs as well as benefits of requiring such information to be produced. The record is clear that requiring SCE to provide the information that LA County initially sought would have been unduly burdensome, although it is somewhat less clear that a requirement limited to the provision of ratepayer impact analyses would be as burdensome to SCE. However, we remain concerned that the benefits of such a proposal may not justify the costs. SCE already provides a bill insert to customers describing the impacts of its rate proposals by customer class, and we can only presume that LA County is asking that SCE provide significantly greater detail than bill inserts provide.

We will not, by today's decision, order SCE to provide more detailed rate impact information than it is currently required to provide to customers. Nevertheless, we urge SCE to explore cost-effective means of providing customers with more meaningful information about the impacts of its rate proposals on the various rate classes. SCE should implement those means as appropriate. In addition, we will continue our existing practice whereby Commissioners and ALJs assigned to individual proceedings may, as they deem appropriate, determine that additional notice to customers about rate proposals and their impacts may be needed.

We will implement one aspect of LA County's proposal. Whenever SCE files a rate proposal before this Commission that requires bill insert or similar notice to customers, SCE should ensure that the content of the notice is also posted on its website in a manner accessible to customers. While we decline to specify the detailed manner in which this should be accomplished, it should be possible for those who access the website to easily locate such notices for all open proceedings for which the requirement is applicable.

### 5.3. Service Fees and Other Operating Revenues

#### 5.3.1. Ratemaking Policy Considerations

Although Phase 2 of this GRC addresses most issues regarding the utility's rate and tariff structure, i.e., how the utility's authorized revenue requirement is to be collected from the various classes and categories of customers, SCE, ORA, and TURN have introduced and responded to proposals for various service fees in this phase of the proceeding. Other Operating Revenue (OOR), which includes the revenue for such fees, is credited to the cost of service. Therefore, OOR reduces on a dollar for dollar basis the revenues that must be collected through base rates. To the extent that our adopted service fees are lower than requested by SCE, and produce less revenue than SCE forecast, SCE's base revenue requirement would be increased accordingly.

SCE proposes increases in service fees for returned checks, service establishment, and disconnects and reconnects for nonpayment. In addition, SCE proposes to institute a residential late payment charge (LPC). SCE states that these proposed fees would result in an increase in OOR of approximately $21 million.

ORA and TURN oppose SCE's proposed LPC due to its impact on low-income families, a concern echoed by Greenlining. ORA proposes more moderate increases to the various fees than those proposed by SCE. TURN proposes elimination of the service establishment fee and initiation of a direct access customer charge. We will address these proposals in the remainder of Section 5.3. We first address overarching policy for the various proposals.

***Discussion***

SCE takes the position that, where possible, the cost of services should be assessed directly on those customers responsible for those costs. SCE maintains that doing so sends appropriate price signals and serves to reduce rates for all customers. SCE's proposals for service fees are offered to further this objective.

To the extent that an identifiable service is provided to a specific customer without charge or at a charge that is below the incremental cost of providing the service, the general body of ratepayers subsidizes the customer receiving the service. Moreover, if a cost-based service charge induces customer behavior (for example, timely bill payment) that results in lower overall utility costs, then both the utility and ratepayers alike may benefit from increased efficiency.

However, we must balance costs with a host of other ratemaking considerations. In D.96-01-011, 64 CPUC 2d 241, 287, when considering a proposed service connection fee, the Commission reiterated that:

> [C]ost is not the sole factor relevant to our inquiry. As we stated in D.91-12-075, 42 CPUC 2d 566, 591-592:
>
> "Our past decisions have never held that just and reasonable rates, the statutory standard (PU Code §§ 451 and 728), had only one component – costs. We have always held that factors such as conservation, affordability, market price and equity had to be factored into the rates. Cases which most strongly supported cost-based rates invariably tempered those statements with language which showed our concern for other ratemaking factors…
>
> "A reading of the PU Code leaves no doubt that the Commission must look beyond costs when setting rates. ... There is nothing in the Code which equates cost-based rates as being a synonym for just and reasonable rates, or as the sole standard by which rates are considered just and reasonable."

In the same decision, in adopting a fee at a lower level than had been proposed by SCE, the Commission took note of the fact that an increased charge would disproportionately impact low-income customers. (*Id.*, 288.)

In D.96-04-050 (65 CPUC 2d 362, 436-440), the Commission ordered the phased elimination of rate discounts for SCE's employees and retirees. The phase-out was suspended when Section 368(a) was adopted, and in Phase 2 of this proceeding SCE proposes to continue the 25% discount unless the Commission terminates employee/retiree discounts for other utilities. (SCE's Phase 2 testimony, Exhibit SCE-16.) We will address this proposal in Phase 2. At this time, we merely note that SCE apparently agrees that cost considerations are not exclusive when setting tariff structures.

#### 5.3.2. Late Payment Charge

SCE proposes the institution of a Residential Late Payment Charge (LPC) of 0.9% per month for customers who fail to pay their bill within 19 days of its receipt. The Commission denied a similar proposal by SCE in the 1995 GRC, while stating that it would reconsider the matter when the Southern California economy significantly improved and SCE's then new computer system, which can accurately track the payment receipt date, became operational. (D.96-01-011, 64 CPUC 2d 241, 289.) SCE claims that both of these conditions now exist, as evidenced by the decline in unemployment from 1995 to 2001 and by the fact that the CSS is now fully operational and virtually 100% of payments are posted by the next day after their receipt.

ORA opposes the LPC based on its concern that the residential LPC will have a disproportionate impact on low-income customers. ORA believes that an LPC will compound the problems of those customers whose payments are late owing to inability to pay. ORA also believes that some customers who face a late payment charge will contact the company to dispute the charge, adding to customer service costs. Moreover, ORA claims, the LPC is inefficient due to the relatively high uncollectible rate estimated by SCE (5%) compared to the overall uncollectible rate (0.311%) recorded in 2000. Finally, ORA believes the LPC is particularly inappropriate at this time due to the recent rate increases to cover higher generation costs.

Joining ORA in opposition to the LPC, TURN submits that economic indicators are declining and that instituting such a charge will create an economic hardship. Referring to data provided by SCE, TURN notes that unemployment rates for the SCE service territory were 8.9%, 7.9%, 7.6%, 6.5%, 6.1%, 4.8%, 4.5%, 5.5%, 6.1%, and 6.0 % for the 10 years from 1994 to 2003, respectively (forecast data for 2002 and 2003). Moreover, TURN contends, U.S. unemployment data for November 2002 suggest that SCE's data may be out of date. If the Commission adopts a residential LPC, TURN proposes that it be limited to bills under $40, and that it be waived if the customer is put on a payment plan.

***Discussion***

SCE's proposed residential LPC upholds the basic principle that those customers who pay late should be responsible for the costs associated with late payments. Moreover, the Commission's stated conditions in D.96-01-011 for consideration of an LPC have been met. No party contends that SCE's CSS is incapable of accurately tracking and recognizing payment receipt dates. TURN disputes SCE's contention that economic conditions, as measured by unemployment in SCE's service territory, have improved sufficiently, but we note that at worst, unemployment was forecast to rise to 6.1% and 6.0% in 2002 and 2003, respectively. These rates are significantly below the 1994 and 1995 rates of 8.9% and 7.9%, respectively, that immediately preceded the issuance of D.96-01-011. The 6.0% forecast for 2003 is also significantly below the 10-year average of 7.1%. TURN's reference to late 2002 national employment data does nothing to change this conclusion.

The parties' concern for the impact of a residential LPC on low-income customers is not without merit. However, the evidence shows that the financial impact on individual low-income customers would not be significant. In any event, SCE has agreed to exempt CARE customers from the application of the LPC, a proposal that we approve. This is consistent with D.95-12-055, where a residential LPC was approved for PG&E with a CARE customer exemption.

ORA is concerned that a new residential LPC could result in increased customer calls, and increased costs. However, there is no study or analysis to support this opinion, and it is just as likely that the residential LPC could reduce the number of calls relating to credit extensions and disconnect notices, since more people will have an incentive to pay on time.

SCE has shown that the Commission's conditions for consideration of a residential LPC have been met, that the LPC will promote cost causation principles, and that low-income customers will not be unduly impacted. SCE's proposal is therefore adopted. TURN's alternative proposal to limit application of the residential LPC to bills under $40 and to waive the charge if the customer is put on a payment plan will not be approved due to the costs and complications involved in setting up and maintaining the processes and systems needed to implement these exceptions.

SCE proposes an interim balancing account for treatment of LPC revenue, as it expects the revenue to vary significantly over the next two years. We will approve this uncontested proposal.

#### 5.3.3. Service Establishment Charge

TURN recommends that the service establishment charge for customers requesting a new service be eliminated due to its disproportionate impact on low-income ratepayers and renters, who move more often than homeowners and the more affluent. In the Los Angeles-Long Beach Standard Metropolitan Statistical Area (SMSA), 28% of renters (including 39% of renters below the poverty line) moved in the past year, while only 7% of homeowners moved in the past year. For the Riverside-San Bernardino SMSA the data showed that 47% of renters (including 54% of renters below the poverty line) moved in the past year, compared to 9% of homeowners. Because renters have lower average incomes than homeowners, the percentage of households moving in the past year is strongly related to income.

TURN maintains that the existence of this charge does not reduce the utility's costs because a customer's decision to move is generally not affected by the charge. TURN contrasts this to a late payment and reconnection charges, which may influence customer behavior and thereby reduce costs.

SCE accepts most of TURN's evidence and analysis but it does not concede these are reasons to abolish the charge. SCE asserts that not all people who move often are poor or less fortunate, and that those who are have other remedies to make electricity available to them at a reduced rate. SCE maintains that costs related to new service establishment are directly attributable to customers moving into a new business or home, and that these costs should be borne by those who cause them to be incurred.

***Discussion***

Even though low-income ratepayers and renters move more often and therefore incur the service establishment charge more often than other ratepayers, that does not establish conclusively that low-income ratepayers and renters are unduly impacted by the charge. Clearly, low-income ratepayers and those who rent would benefit from waiver or elimination of the charge, but the evidence does not persuade us to weigh that benefit more heavily than our concern for establishing service charges on principles of cost causation. Moreover, as SCE points out, these customers have other remedies to make electricity available to them at a reduced rate, including the CARE discount. Further, there are customers who attempt to avoid paying their bills by reapplying for service under a new or assumed name, leaving an unpaid balance on the former account, which would eventually go to write-off. While this is not a major factor (for the reasons explained by TURN), neither should we ignore it. Finally, as explained below, we are adopting the more moderate service charge increases advocated by ORA instead of those proposed by SCE, which will mitigate somewhat the impact of this charge on low-income ratepayers and renters. For all of these reasons, TURN's proposal to abolish the service establishment charge is denied.

### 5.3.4. Direct Access Customer Charge

TURN recommends that a $5 per month customer fee be charged to all direct access customers over 20 kW on an interim basis, with the intent to further evaluate and design direct access service fees that are more cost based in the second phase of this proceeding. TURN states that this would generate $378,420 in OOR. Asserting that there are many unsettled aspects of direct access service that should be resolved first, SCE contends that an interim $5 fee should not be adopted at this time but perhaps reconsidered later.

***Discussion***

A $5/month fee is a minimal cost increase to large direct access customers, resulting in rate impacts of less than 1/100th of a mil per kilowatt-hour. It would not materially change the economics of their direct access transactions. It would, however, reduce the current subsidy to direct access customers resulting from the fact that bundled customers currently pay about 90% of the direct access costs recorded in Accounts 901, 902 and 903. The fact that there are many unsettled aspects of direct access service is not dispositive, since TURN is proposing the customer charge solely on an interim basis. We will adopt a $5 per month direct access customer service charge on an interim basis, along with $378,420 in OOR, subject to further consideration in Phase 2 of this GRC or other appropriate proceeding.

#### 5.3.5. Level of Service Charges

SCE has proposed cost-based service charges, resulting in significant increases. In one case the increase is 90%. ORA proposed a schedule of more moderate fee increases under which no fee rises by more than 26%. The following table shows the current and proposed fees.

**Current and Proposed Service Charges**

| | | Current | SCE | ORA |
|---|---|---|---|---|
| Returned Check | | $ 9.00 | $11.00 | $10.00 |
| Reconnect at Meter | Next day | $12.50 | $17.00 | $14.00 |
| | Same day | $20.00 | $32.00 | $25.00 |
| | Night/weekend | $25.00 | $44.00 | $30.00 |
| Reconnect at Pole | Next day | $30.00 | $57.00 | $30.00 |
| | Same day | $50.00 | $60.00 | $50.00 |
| | Night/weekend | $60.00 | $74.00 | $60.00 |
| Service Establishment | Next day | $10.00 | $17.00 | $12.00 |
| | Same day | $17.50 | $27.00 | $22.00 |
| Field Assignment | | $10.00 | $18.00 | $11.00 |

***Discussion***

SCE has agreed to ORA's proposed fee for returned checks but otherwise continues to oppose ORA's fees proposal. We find that ORA has presented a schedule of fees designed to reflect cost responsibility, while also moderating percentage increases and taking account of affordability concerns. ORA's proposal reflects a more reasonable balancing of ratemaking considerations, including affordability, whereas SCE's proposal reflects too much emphasis on the role of costs as a ratemaking consideration. ORA's proposed schedule of fees is more reasonable and will therefore be adopted.

Since we are adopting ORA's proposals for service charges, we will likewise adopt OOR associated with those charges. We also adopt ORA's correction to SCE's proposed Direct Access Service Fee OOR amount of $256,000. The correct amount, which we adopt, is $368,000.

## 5.4. Capital

### 5.4.1. SCE's Showing

Through inadvertency, SCE did not provide justification for $3.408 million in CSBU-related capital additions (FERC Account 101) in its direct showing. The capital additions were, however, reflected in SCE's results of operations showing. ORA pointed out this omission in its testimony, and SCE subsequently provided justification for the expenditures with its rebuttal showing. The capital additions at issue are for furniture and equipment, building improvements, and tools and test equipment.

ORA does not dispute the reasonableness of SCE's CSBU capital additions but it nevertheless proposes their disallowance on procedural grounds. Also, ORA concedes that SCE's omission of the necessary justification for the capital additions was inadvertent. ORA contends that providing justification in rebuttal testimony is too late for parties to analyze the showing. ORA therefore argues that SCE has failed to meet its burden of proof.

***Discussion***

The Commission has held that it is not permissible for utilities to hold back on the presentation of salient information until the submission of rebuttal testimony.[42] We would be well within our rights and responsibilities if we were to disallow these capital additions on procedural grounds as advocated by ORA. However, taking into account the special circumstances applicable here, we find that our procedural requirements may be waived in this instance.

SCE obviously made a simple mistake. Its failure to include the justification with the application was clearly not part of a litigation strategy whereby SCE would wait until rebuttal to spring this information on unsuspecting parties. The results of operations study submitted with SCE's initial showing reflected the capital additions. Presumably, if ORA had identified this deficiency during its review of the Notice of Intent, SCE would have been alerted to the omission and could have included the justification with its application.

ORA has made no claim or showing that it attempted to have SCE provide the justification through a data request. Given the relatively small amount of material provided by SCE to justify inclusion of the capital additions (approximately two pages), and the relatively small dollar amount of additions at issue, we are not prepared to conclude that ORA and other parties would have

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[42] It is unacceptable for utilities to "offer only the most minimal support for their rate requests, choosing instead to wait to see what subjects appear to be of interest to [ORA]," then, in response to ORA's concerns, provide focused rebuttal. (D.92-12-019, 46 CPUC 2d 538, 764.)

had insufficient time to review the showing had they made a timely data request upon learning of the mistaken omission. As a matter of equity in this proceeding, we will consider SCE's justification on the merits rather dismiss the entire CSBU capital additions request on procedural grounds. This is based on consideration of the circumstances described herein and is not a license for SCE or any other utility to depend on similar waivers of our procedural rules in the future.

ORA expresses concern that "failure to deny Edison's inadequate and tardy request will lead to the belief among utilities that they do not have to provide justification for their requests when they file their applications and during their direct cases—that the Commission will allow them to file their cases during the rebuttal phase of the case." (ORA Reply Brief, p. 3.) We understand ORA's concern, and we state emphatically that any utility harboring such beliefs should be disabused of them. Notwithstanding today's decision, we reserve the right to deny consideration of any "rebuttal" evidence that could have and should have been included with the utility's direct showing, even where, as here, a simple mistake of omission has been made by the utility.

Although ORA declined to do so, we have reviewed the content of SCE's justification for its CSBU capital additions. SCE contends that the capital additions at issue are typical, noncontroversial expenditures. However, of its total request for $3.408 million, $956,000 is for the energy centers and $150,000 is for the pump test program. Since we have denied SCE's request for O&M funding of these programs, and SCE has not demonstrated that GRC funding of the program's capital requirements is reasonable given the O&M denial, we will disallow the associated capital expenditures, for a total disallowance of $1.106 million.

### 5.4.2. Real Time Energy Metering (RTEM)

In 2001, SCE embarked on an RTEM project that involves the purchase and installation of advance metering and related communication, information and notification systems for all bundled end-user accounts with monthly maximum demands of 200 kW or more. The project provides these customers with the ability to access their interval usage information via the Internet. The scope of work focused on purchase and installation of 12,000 meters and communications equipment, development of communications infrastructure, operational modifications, and customer education. SCE estimates the total cost of its RTEM project to be $27.649 million for capital requirements and $3.462 million for ongoing operational expense.

A significant portion of these RTEM costs will be offset by funds from the California Energy Commission (CEC) that are derived from appropriations authorized by ABX1-29 and SBX1-5.[43] In April 2001, SCE responded to a CEC RFP on the use of state funds for the RTEM project. In May 2001, CEC agreed to allocate funding to SCE on a flat cost per meter basis, and SCE determined that this funding was insufficient to recover its total implementation costs. As a result, SCE filed Advice Letter 1549-E requesting a memorandum account to track all the RTEM project costs for future recovery. The advice letter was approved by Resolution E-3746 dated June 28, 2001.

TURN takes the position that SCE should not receive ratepayer funding for the portion of its RTEM capital additions request that is not covered by the

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[43] SCE expects to receive approximately $19 million pursuant to contracts with the CEC, consisting of $16.8 million in ABX1-29 funds and $2.52 million in SBX1-5 funds. Any CEC funding received will offset the revenue requirement associated with the RTEM costs.

$16.8 million CEC contract. According to TURN, SCE should not have signed a contract with CEC for RTEM funding with any expectation of such ratepayer funding. TURN proposes a capital additions disallowance of $10.8 million for what it calls cost overruns. SCE disputes several aspects of this proposal.

***Discussion***

TURN has not shown that RTEM project cost overruns have occurred. SCE knew at the outset that CEC funding would be inadequate for the project that SCE had in mind, and its Advice Letter 1549-E identified this fact. However, the fact that there were no cost overruns does not resolve the issue. SCE must still show that it was reasonable for it to embark upon a project requiring $10.8 million in ratepayer funded capital additions.

In support of its expenditures, SCE emphasizes the mandatory nature of the RTEM program. It is true, as we stated in D.01-08-021 "that ABX1 29 does require mandatory TOU or RTP metering for customers whose usage is greater than 200kW of peak demand" and "that meter installation is mandatory under ABX1 29." (D.01-08-021, p. 5.) However, this mandatory aspect of the legislation is applicable to the metering capability that must be in place for customers. SCE has not shown that it was mandated to undertake a project that required ratepayer funding of millions of dollars over and above what the Legislature appropriated. TURN's proposed capital additions disallowance of $10.8 million is therefore approved.

In its reply brief, SCE states that "total RTEM project costs are not at issue in this GRC;" that it simply is not the case that this GRC is "by default, the appropriate regulatory forum to review such expenditures;" and that "SCE is not requesting in the GRC recovery of RTEM project costs already incurred and recorded in the memorandum account." (SCE Reply Brief, p. 92.) However, in its direct testimony that accompanied the GRC application, SCE placed the issue squarely before the Commission in this GRC:

> The CEC agreed to provide us with their (partial) funding upon approval of our advice letter. On June 28, 2001, the CPUC issued Resolution E-3746 approving our memorandum account treatment. Thus, *we are including capital costs (excluding depreciation expense) associated with SCE's additional investment and the associated annual on-going O&M expense in this application*. (Exhibit 37 p. 88, emphasis added.)

Having placed the issue for consideration in this GRC, SCE cannot now, after the matter has been litigated, claim that some other proceeding is more appropriate for considering the disputed RTEM project capital costs.

### 5.5. Service Guarantees

SCE's Senior Vice President of Customer Service testified that the company strives to provide a high level of customer service and satisfaction, and that in 2000, under the customer satisfaction measure of the PBR mechanism, 76% of SCE's customers responded that they were "completely satisfied" or "delighted" with SCE's customer services. Stating that it seeks to ensure that SCE lives up to this service quality commitment, and to compensate customers when SCE fails to do so, ORA proposes that an eight-point service guarantee program be mandated by the Commission.

Under the program proposed by ORA, SCE would guarantee that it will (1) meet agreed appointment times; (2) investigate non-emergency situations and communicate results to customers within seven days of a customer request; (3) decide on a course of action to resolve a complaint and communicate it to the customer within three working days, and communicate the complaint's resolution to the customer within 10 working days, or 30 working days when an off-site meter test is required or an on-site home audit is requested; (4) meet the agreed date for installing a new meter and turning on service for a customer; (5) respond to service interruptions within four hours after receiving a customer report by either restoring service or informing the customer of when they can expect service to be restored; (6) restore service within 24 hours; (7) provide at least three days notice of a planned interruption in service; and (8) issue an accurate first bill to a new customer account within 60 days of service initiation. Each time SCE fails to meet one of these guaranteed standards, it would be required to pay the affected customer $50 from shareholder funds. SCE would be required to report program results (number of claims made, claims paid, and amounts of money paid) to the Commission on a quarterly basis. Additionally, TURN recommends that SCE continue to report data on several service-related parameters (failures of distribution facilities, failures of cable connections, number of erroneous disconnects, and street light outage) that SCE has been required under its PBR mechanism.

ORA states that its proposal is based on a voluntary program that SCE operated from 1995 to 2001. ORA notes that this was a period when SCE was faced with potential competition for its customers. ORA is concerned that now, with no competition for customers, SCE could merely pay lip service to ensuring customer satisfaction without having to immediately answer to them. ORA states that its proposal is not meant to be punitive, but instead is meant to provide an incentive for Edison to maintain high-quality customer service.

SCE opposes this proposal, although, under specified conditions, it would agree to consider implementing some aspects of ORA's proposed program (agreed date for meter installation and service turn-on, response to service interruptions within four hours, service restoration within 24 hours). Among other things, SCE is concerned with the cost of the proposed program. SCE estimates that start up costs would be $708,000, annual operating costs would be $534,000, and "base level" credit costs would be $838,000 annually.

SCE maintains that the following design principles should be applied in any adopted customer guarantee program:

- A service guarantee program should enhance overall customer satisfaction at a reasonable cost.
- All of the costs to implement and administer a service guarantee program should be recoverable through rates.
- A service guarantee program should be based on standards and expectations that are achievable.
- Service guarantee credits should be fair, balanced, and consistent with the other California utilities.
- A service guarantee program must be simple, clearly defined, easy to understand, and include appropriate exclusions.
- A service guarantee program should complement existing customer satisfaction efforts and avoid duplication.
- A service guarantee program should focus on a few critical services that are most important to customers.

***Discussion***

This GRC is the appropriate venue to address and propose a customer service guarantee program; the General Rate Case is the traditional forum in which the revenue requirement associated with providing reasonable adequate service is traditionally made. Defining the level of customer service and appropriate enforcement mechanisms in this GRC will assist SCE and the public in finding common ground on the level of serviced expected of a franchised provider. ORA has presented a well-thought out program that would address certain areas of customer satisfaction performance by providing compensation to certain customers who have been inconvenienced by SCE. We find this to the be proper place to adopt customer service standards.

An essential feature of ORA's customer service guarantee program is the use of "compensatory rebates" penalties; penalties that accrue to the customer when SCE fails to meet a customer service standard. This is a self-enforcing mechanism that can create a significant incentive for SCE to meet the adopted standards. However, we are concerned that the levels proposed by ORA may be excessive. We will therefore modify ORA's proposed standard penalties as follows:

1. (meet agreed appointment times) $30 credit
2. (non-emergency investigations) $30 credit
3. (complaint resolution) $30 credit
4. (new installations/service) $30 credit
5. (service interruptions) $30 credit
6. (service restoration) $30 credit for each 24 hours without service
7. (planned interruption notification) $30 credit
8. (first bill) $30 credit

Adopting a rebate enforcement element to the mandatory customer service guarantees requires that we monitor the program to ensure efficacy and avoid potential abuse. We will adopt ORA's recommendation to require SCE to report program results (number of claims made, claims paid, and amounts of money paid) to the Commission on a quarterly basis. Further, we also adopt TURN's recommendation to require SCE to continue reporting (1) failure rates of distribution facilities listed in GO 165 and cable connections, (2) erroneous disconnects, and (3) street light outages using the same similar past methodologies.

## 6. Administrative and General

### 6.1. Introduction

Section 6 addresses contested Administrative and General (A&G) issues raised by ORA, which addressed A&G issues comprehensively, as well as issues raised by Aglet, TURN, and Greenlining. As shown in the Joint Comparison Exhibit (Exhibit 403, p. 315), SCE's total A&G expense forecast is $552.1 million (constant 2000 dollars), while ORA's forecast is $476.348 million. This represents a difference of $75.752 million.

### 6.2. Financial Organizations and Capitalized Expenses

#### 6.2.1. Account 930 – Participant Credits

SCE bills the minority participants of facilities such as SONGS for their share of the A&G costs to operate these facilities. Also, the majority owner of Palo Verde and Four Corners bills SCE for their A&G costs. These transactions are tracked in Account 930.

SCE forecast an overall non-labor credit of $8.087 million in 2003 for Account 930, an amount equal to recorded expenses for 2000. Using a five-year average of 1996-2000 data, ORA forecast an overall non-labor credit of $12.192 million in 2003 for Account 930, yielding a difference of $4.105 million.

***Discussion***

The recorded non-labor amounts in Account 930 are shown in the following table:

**FERC Account 930 Non-Labor**
**(Constant Dollars X 1000)**

| 1996 | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|
| (12,687) | (15,763) | (14,213) | (10,208) | (8,087) |

The consistent decline from 1997 to 2000 to approximately one-half the 1997 level suggests that a declining trend may exist, throwing into doubt the reasonableness of using a five-year average. These numbers do not suggest mere variability as ORA contends, nor do we find convincing evidence within the underlying data in Exhibit 211 that variability warrants the use of a five-year average for this account.

SCE has presented evidence explaining why these credits have declined from 1997 to 2000. The methodology used to calculate participant credit rates is defined in the Participant Billing Operating Agreements between SCE and the participants. The rates have been declining from the mid-forty percent level in 1997 to the mid-thirty percent level in 2000. Also, the SONGS participation rate, which is the largest component of the Account 930 expenses, will remain constant through at least 2003 pursuant to a negotiated agreement.

We find that recorded data for 2000 is most representative of test year amounts for Account 930. We therefore adopt SCE's test year 2003 forecast of $8.102 million for Account 930 (Labor and Non-labor).

#### 6.2.2. Capitalized Pension and Benefits (P&B)

SCE computes the total amount of P&B expenses, subtracts the capitalized portion, and assigns the remainder as O&M expenses. A capitalization rate is determined to estimate the capitalized portion. Capitalized P&B expense is recorded as a credit to Account 926.900 (Employee P&B Transferred) and a debit to Account 107 (Construction Work In Progress).

SCE initially used a capitalization rate of 24% but during the proceeding changed its recommendation to 25% to reflect a correction identified by TURN. TURN recommends a capitalization rate of 29.43% based on a regression analysis of data from 1990-2000 that relates capitalized labor to gross plant additions and assumes SCE's forecast of capital additions is adopted. (TURN recommends that this rate be recomputed to reflect the adopted capital additions.) Compared to SCE's forecast, TURN's recommended approach results in an estimated difference of $14.893 million in Account 926 and an additional $4.703 million in capital overheads.

***Discussion***

TURN's regression methodology is potentially more reliable as a forecast methodology than SCE's selection of a single year's data, but SCE has raised doubts about its validity in this GRC because of the fact that SCE plans to accomplish the increased capital additions associated with its Infrastructure Replacement Program with contract labor, which does not receive SCE P&B.

The capitalization rate percentages associated with recorded spending, as shown in Exhibit 299, p. 10, are set forth in the following table:

**Capitalization Percentages Based on Recorded Capitalized and Total Utility Labor**

| 1996 | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|
| 20.3% | 20.3% | 22.2% | 25.4% | 27.8% |

Based on the method used in prior rate cases and 1999 recorded amounts, SCE proposes a capitalized P&B rate of 25% for 2003 (25.4% rounded down to 25%). In light of the apparent increasing trend as shown in the table above, we will adopt TURN's secondary recommendation to use the 2000 value of 27.8%.

### 6.3. Legal And Regulatory, Workers' Compensation, Insurance

#### 6.3.1. Account 923 (ORA Audit Recommendations)

ORA recommends that $407,071 be removed from Account 923 for outside counsel expenses incurred in 2000 to prepare for a potential involuntary bankruptcy filing. Because SCE used a three-year average to forecast 2003 expenses, this would result in a $136,000 reduction to SCE's 2003 forecast. ORA also proposes a $62,629 reduction to recorded 2000 expenses in Account 923 to remove costs of litigating SCE's Filed Rate Doctrine lawsuit against the Commission, which results in a test year reduction of $21,000.

***Discussion***

ORA's recommendations rest on the premise that these outside counsel expenses are non-recurring (bankruptcy) and on the basis that a settlement was reached (Filed Rate Doctrine lawsuit). We find ORA's showing with respect to the bankruptcy expenses persuasive. The argument that each litigation matter is unique, and the implication that there can be no non-recurring litigation expense, is without merit. We are not prepared to assume that it is reasonable to expect that the level of spending on bankruptcy litigation in 2000 will continue. ORA's proposed removal of $136,000 associated with bankruptcy expenses in the test year is reasonable and will be adopted.

Even if all appeals regarding the Filed Rate Doctrine lawsuit were exhausted, we are persuaded that the costs SCE incurred are nonetheless representative of future litigation costs. ORA's proposed test year reduction of $21,000 will not be adopted.

#### 6.3.2. Accounts 923 & 928 (Forecast Methodology)

Aglet contests SCE's use of a three-year average for outside counsel expenses (1998-2000), proposing instead that a two-year average be used (1999-2000). Aglet's recommendation would result in a reduction from SCE's forecast of $2.005 million in Account 923 and $0.729 million in Account 928, or a total of $2.734 million

***Discussion***

According to Aglet, SCE's three-year average methodology does not adequately reflect the reduced legal workload associated with the decline of restructuring implementation work, the signing of long-term procurement contracts by the DWR, reduction of the residual net short, generation divestiture, and the financial crisis. However, 2000 expenses were low due to the energy crisis, and legal and regulatory work associated with the energy crisis has been increasing. The assertion that the execution of the DWR contracts and the decrease in average residual net short will lead to a decreased legal workload is contrary to SCE's direct showing and is not adequately supported. Finally, the assumption that the declining legal work associated with power plant divestiture should result in a lower forecast for Accounts 923 and 928 outside counsel expenses is not adequately supported, as legal costs incurred for divestiture were charged to capital work orders. We conclude that use of a three-year average to forecast outside counsel expenses is reasonable and should be adopted.

#### 6.3.3. Account 928 (GRC Expenses)

Within Account 928, SCE recorded expenses of $1.3 million in 2000 for GRC expenses. SCE bases its test year forecast of GRC expenses on the 2000 recorded value, i.e., it did not use three-year averaging. SCE believes that the $1.3 million spending level will recur with the return to conventional cost of service ratemaking.

Aglet proposes that SCE's 2003 Account 928 forecast be reduced by $130,000 (10% of $1.3 million) based on the contention that SCE will gain experience in this GRC that will improve its efficiency in preparing the next GRC. SCE counters that rate case expenses are increasing due to additional requirements imposed on the company, the increased scrutiny on SCE's cases, and the involvement of new parties. SCE questions the qualifications of Aglet witness Weil to make the professional judgment that a 10% efficiency gain is reasonable to achieve.

***Discussion***

We accept Weil's qualifications to make the professional judgment that a 10% efficiency gain is reasonable. One need not have direct experience with a utility function as a prerequisite to rendering expert opinions regarding that function. However, while SCE should be more efficient, the evidence also suggests that the scope of work to be performed in connection with GRCs has been growing. We are not prepared to conclude that a $130,000 reduction from the 2000 recorded cost is reasonable.

#### 6.3.4. Account 930 (Board Meetings)

SCE's test year 2003 forecast for Corporate Governance activities in FERC Account 930 is $3.3 million. ORA recommends that 2000 recorded expenses in Account 930 be reduced by $133,250. This recommendation is based on limiting ratepayer funding to seven corporate board meetings per year (SCE held 11 board meetings in 2000), resulting in a proposed reduction of $64,500, and removal of $68,750 for retainer fees paid to Directors.

***Discussion***

ORA's recommendation is based on the assumption that the number of board meetings held annually prior to 2000 will resume. The evidence does not support this assumption. SCE has amended its bylaws so that certain officers could call a meeting for any purpose. SCE held more than seven board meetings in 2000, 2001, and 2002. SCE continues to face pressing matters such as its financial health and the shake-up of energy markets. The requirements of the Sarbanes-Oxley Act are likely to lead to greater board oversight of corporate activity, and more board meetings. We accept SCE's forecast without the reduction proposed by ORA.

#### 6.3.5. Property and Liability Insurance Expense

##### 6.3.5.1. Account 924 (Property Insurance Expenses)

SCE purchases nuclear property insurance from Nuclear Electric Insurance Limited (NEIL), a mutual insurance company. From time-to-time, based on current expected losses, surplus funds, and reinsurance available, the board of directors of NEIL may approve a refund to its members.

Based on statements from NEIL's board of directors, SCE forecast a $5.451 million refund in 2003, $5.387 million of which is for SONGS, with the remaining $64,000 for Palo Verde. ORA recommends forecasting the NEIL refund for 2003 by using six-year average of recorded data, or $11.501 million. However, during the proceeding NEIL's board of directors determined the actual refund amount to be allocated to SCE as $7.499 million ($6.890 million for SONGS and $608,302 for Palo Verde). SCE now proposes using the actual refund instead of a forecast.

***Discussion***

The timing of the processing of this GRC made it possible to use actual instead of forecast data for this particular expense. We find that it is reasonable to do so, and therefore adopt SCE's revised request. ORA's concern that the NEIL refunds may be different in 2004 and 2005 is not compelling, since our purpose here is to forecast expenses for 2003.

#### 6.3.5.2. Account 925 (Liability Insurance)

As it did with nuclear property insurance, ORA recommends a six-year average of $560,000 to estimate nuclear liability insurance refunds for the test year. This recommendation would raise SCE's forecast of $239,000 by $321,000.

***Discussion***

ORA has demonstrated that a six-year average is reasonable for this forecast, even though it may actually underestimate the refund. In its opening brief, SCE points to SCE's testimony that "[n]uclear liability insurance is expected to increase over the forecast period" for the same reasons that nuclear property insurance is increasing. (Exhibit 43, p. 52.) This hardly represents convincing evidence that its estimate of $239,000 for refunds is more reliable than ORA's estimate based on a six-year average. ORA's adjustment is reasonable and will be adopted.

## 6.4. Shared Services

### 6.4.1. Shared Services Expenses

#### 6.4.1.1. Business Resources

SCE's Business Resources Unit provides document and drawing management, event and travel services (E&TS), mailing services, and records management and storage services. ORA takes issue with certain non-labor E&TS-related costs. ORA states that it is proposing a forecast of $1.829 million for Business Resources, which would be a reduction of $863,000 from SCE's non-labor forecast of $2.692 million in Account 921. (Exhibit 45, p. 7; Exhibit 188, p. 14-D-6.) ORA states that its reduction is made to normalize non-recurring, unusual, and/or one-time expenditures. Noting that E&TS scheduled employee events that included basketball games at Staples Center and baseball games at

Edison Field, music concerts, etc., ORA states that it removed all such expenses not appropriately charged to ratepayers.

***Discussion***

SCE and ORA have managed to inject considerable confusion into the framing of this issue. SCE's rebuttal testimony and the Joint Comparison Exhibit state that ORA is proposing a reduction of $1.416 million to the Business Resources forecast (Exhibit 299, pp. 32, *et seq.*, *passim*; Exhibit 403, p. 348), but ORA stated earlier in its errata testimony that it is proposing a reduction of $863,000 (Exhibit 188, p. 14-D-6).[44] Although ORA states in its testimony and in its opening brief that it is recommending a reduction of $863,000, ORA jointly agreed with SCE in the Joint Comparison Exhibit that the issue represents a difference between the parties of $1.045 million. In its rebuttal testimony, SCE acknowledged that it failed to provide needed clarification in a data request response, and that this caused confusion. (Exhibit 299, p. 34.) Also, SCE changed its position on at least four occasions. (*Id.*, pp. 36-37.)

Whether the dispute is over $863,000, $1.045 million, or $1.416 million (and as discussed below we find it is none of these), SCE is only requesting $818,000 for E&TS, and only $359,000 for the non-labor portion (Exhibit 45, p. 12). Thus, ORA's request to remove expenses that exceed the company's entire forecast for E&TS is, on its face, at least questionable. SCE clarified that ORA's recommendation affects several areas in the company, not just shared services, but ORA does not acknowledge this clarification.

[44] Adding to the confusion, ORA's errata is internally inconsistent. At page 14-D-4 of Exhibit 188 ORA states that it is estimating $1,275,853 for Account 921 for Business Resources, but at page 14-D-6 ORA indicates that it is correcting this estimate to $1,828,771.

After reviewing the record, we find that the most reliable statement of the dispute is set forth in SCE's rebuttal testimony, Table IV-3 of Exhibit 299 and the accompanying text at pp. 37-38. SCE's last revised forecast of expenses for events handled by E&TS is $865,936, and ORA's recommendation is $374,061, a difference of $491,875.

SCE contends that the remaining events, i.e., those covered by its final request for $865,936, were conducted in furtherance of SCE's utility activities and are representative of the types of meetings that will be conducted in 2003 and beyond. SCE contends that they are not non-recurring, unusual, and/or one-time expenditures. The largest area of disagreement between SCE and ORA is employee awards and recognition ($345,741 of the total $491,875 difference). Among other things, SCE's Information Technology (IT) department held a celebratory "Y2K" event in 2000 at a cost of $265,898, and the Law Department held a retirement function at a cost of $4,348.

Whether or not these are "normal and recurring business expenses within the business world that any given company would incur as an operating expense" (Exhibit 299, p. 40), SCE has not demonstrated that utility ratepayer funding of such celebrations is reasonable or necessary. We conclude that SCE has failed to provide justification and substantiation for the costs of the disputed events, and therefore order a reduction of $491,875. We will reduce SCE's Business Resources forecast by that amount.

#### 6.4.1.2. Investigations Division

SCE forecast $4.671 million for its Corporate Security and Emergency Planning and Preparedness Unit (CS&EPP). The Investigations Division of CS&EPP consists of 14 SCE employees who are responsible for investigating threats and other hostile or criminal acts directed at SCE or its employees.

Examples of its functions include a 2000 incident where a contractor falsified expense reports and timesheets for over $10,000, and a 1998 incident where two persons impersonated SCE employees and fraudulently offered customers a 50% bill discount in return for an advanced fee. In the 2000 incident SCE's investigation led to criminal charges, conviction, and restitution to SCE. In the 1998 incident SCE's investigation led to identification of the suspects and felony convictions.

ORA proposes a $70,000 reduction to SCE's forecast for the non-labor portion of the Investigations Division. These non-labor expenses consist primarily of costs related to contract services, as well as professional expenses associated with background checks. Due to the variability of the non-labor expenses, SCE used a five-year average of recorded data to forecast a test year expense of $204,000. ORA's proposed reduction is based on ORA's use of the last recorded year.

***Discussion***

The historical non-labor recorded/adjusted costs for Investigations are set forth below:

**Investigations Expense – Non-Labor**
**(Constant Dollars X 1000)**

| 1996 | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|
| 214 | 230 | 213 | 232 | 134 |

SCE explains that the reduced expense in 2000 was due to temporary cost reduction measures implemented in 2000 in response to the California energy crisis. (Exhibit 45, p. 26.) SCE maintains that the lower spending level of 2000 is not sustainable. (*Id.*, p. 27.) Absent persuasive evidence to the contrary, ORA's recommendation to use the last recorded year would not be reasonable. ORA's position that a hiring freeze that SCE implemented in 2000 should reduce the need for background investigations lacks persuasiveness. SCE's forecast of $204,000, based on a five-year average, will be approved.

#### 6.4.1.3. Shared Services Support Group

The Shared Services Support Group consist of seven employees responsible for providing centralized support to the organization Vice President. Their functions include business planning and strategy, business improvement, and financial services. Using the last recorded year, SCE forecast expenses of $1.049 million ($767,000 labor and $282,000 non-labor).

ORA proposed reducing the non-labor portion of SCE's request from $282,000 to $177,364, a reduction of $104,636. ORA recommends this reduction to remove the costs of employee awards, mentor luncheons, employee contributions, flowers, and sports events.

SCE agreed to remove $21,129 from its request for items that are non-recurring and items for which SCE agrees there are no ratepayer benefits. These include sporting events and employee contributions, among others. SCE's revised request is $260,871, which is $83,507 greater than ORA's recommendation.[45]

***Discussion***

Although SCE removed some of the disputed expenses for Shared Services Support, SCE contends that expenses for food vendor services, mentor luncheons, and employee awards are appropriate because they support valid

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[45] Without explanation for the difference, SCE and ORA indicate in the Joint Comparison Exhibit that their difference amounts to $92,000. (Exhibit 403, p. 353.) The discrepancy is possibly explained by SCE's failure in some instances to acknowledge ORA's change of position as indicated in Exhibit 188.

business purposes. The disputed expenses support working lunches for the Vice President and managers, which, SCE contends, results in greater organizational effectiveness. They also support lunches for mentor programs that, according to SCE, strengthen the organization, provide for career enhancement, professional growth, and job effectiveness. Finally, SCE maintains that employee awards and recognition programs foster continuous improvement and achievement of long-term objectives, and create an environment of valued contribution that promotes employee retention.

We find SCE's justification for the disputed expenses unconvincing. In particular, SCE has not adequately demonstrated that ratepayer funded lunches for executives and managers and for mentor program participants is necessary or appropriate. ORA's proposed reduction of $83,507 will be adopted. The adopted non-labor expense for the Shared Services' Support Group in Account 921 is $177,364.

#### 6.4.1.4. Corporate Real Estate

##### 6.4.1.4.1. Market Studies, Title & Mapping

ORA removed costs in Account 921 for market studies and increased title and mapping services that were performed by SCE in connection with studies for its Revenue Enhancement section. ORA removed a total of $323,000 on the basis that these were one-time, nonrecurring expenditures.

SCE disputed ORA's recommendation, contending that the services are necessary to prepare properties for marketing to developers, which ultimately benefits ratepayers by the generation of OOR.

In its opening brief, TURN pointed out that under the gross revenue sharing mechanism adopted in D.99-09-070, costs for land title services and mapping support are not to be included in rates.

***Discussion***

We appreciate TURN's pointing out that compliance with D.99-09-070 requires exclusion of this expense. SCE readily admits in its reply brief that TURN's recommendation is appropriate. SCE states that it overlooked the adjustment due to an internal miscommunication. We find this oversight troubling, and we therefore adopt TURN's proposal to require SCE to certify in an advice letter filing that none of its GRC requests include expenses that, pursuant to D.99-09-070, are to be borne by shareholders. SCE's request for Account 921 is reduced by $323,000.

#### 6.4.1.4.2. Landscape Maintenance

ORA takes issue with SCE's inclusion of $96,000 in expenses for landscape maintenance activities consisting of such activities as turf replacement, removal and replacement of ground cover, irrigation work, replacement of dead trees, etc. ORA believes that these expenses should be removed on the basis that they are one-time, nonrecurring costs.

***Discussion***

ORA has not adequately demonstrated why the disputed landscaping expenses would be nonrecurring activities ineligible for consideration in the forecast. This proposed reduction will not be approved.

#### 6.4.1.4.3.Account 935 Forecasting Method

SCE has 70 non-electric facilities encompassing 170 separate buildings and tens of thousands of square feet of parking surface. SCE used the last recorded year to forecast test year expenses $6.740 million for Account 935 – Maintenance of General Plant. These expenses cover maintenance of structures and parking areas at SCE's non-electric facilities and include roof patching, minor asphalt repairs, interior drywall patching, and painting. They also include repair of office furniture and equipment, minor building alterations, and remodels. SCE states that these expenses are increasing due largely to the increasing average age of the facilities.

ORA used a five-year average to arrive at a forecast of $6.041 million, or $699,000 less than SCE's forecast. ORA contends that a five-year average is appropriate to account for normal year to year fluctuations.

***Discussion***

Because SCE's non-electric facilities are aging, and facility age significantly influences maintenance costs, use of the last recorded year instead of a five-year average is appropriate for this account. SCE's forecast is therefore approved.

### 6.4.2. Shared Services Capital

#### 6.4.2.1. Introduction

SCE's forecast of shared services capital expenditures is $25.000 million in 2002 and $34.617 million in 2003, or a total of $59.617 million. ORA recommends adoption of capital expenditures of $10.896 million in 2002 and $8.255 million in 2003, or a total of $19.151 million. ORA's recommendation represents a proposed disallowance of $40.466 million. Section 6.4.2 addresses ORA's claims regarding the adequacy of SCE's showing, projects over $1 million, and blanket work orders.

#### 6.4.2.2. Adequacy of SCE's Showing

ORA contends that SCE did not provide sufficient documentation to fully substantiate its shared services capital expenditures forecast, that SCE did not provide cost benefit analyses to demonstrate the value of demolishing and major remodel projects, and that SCE did not provide sufficient documentation for ORA to independently reconstruct the forecast. ORA believes that the forecast costs for certain projects appear to be based primarily on "wish lists."

***Discussion***

SCE's direct testimony that accompanied the application included approximately 60 pages of text, tables, and figures explaining and supporting SCE's shared services capital expenditures request. (Exhibit 46, pp. 15-75.) SCE provided additional, comprehensive information to ORA in response to data requests (e.g., Exhibit 193), and ORA has not shown that SCE unreasonably failed to respond to any ORA data requests pertaining to this issue. While we will address the reasonableness of various components of the disputed capital additions in the remainder of Section 6.4.2, we find no basis for concluding that SCE has failed generally to justify its requests, or has merely presented wish lists.

We will not disallow disputed shared services capital additions on the basis of such general claims of an inadequate showing. Thus, ORA's recommended disallowances of $1.593 million for Various Rights-of-Way Acquisitions, $15.107 million for Field Facility Infrastructure Improvements, and $2.314 million for projects under $1 million, which are not based on any more specific ORA analysis, will not be approved.

#### 6.4.2.3. Projects Over $1 Million

##### 6.4.2.3.1. Strategic Facilities Plan

SCE determined that certain of its non-electric facilities needed replacement or major remodeling, but for some time it did not implement remodeling projects due to changes in the business environment. By 1998, SCE determined that the combination of the facilities' age, upgrades required by law (such as the Americans With Disabilities Act or ADA), and the need for telecommunications and electrical upgrades were converging. To address this concern, SCE developed a Strategic Facilities Plan (SFP) that focused largely on the General Office (GO) complex in Rosemead and also addressed facilities in

Westminster, Santa Ana, Alhambra, and Irwindale. SCE expended $32.342 million on the SFP prior to 2001, did not make SFP expenditures in 2001, and forecast SFP capital expenditures of $5.247 million in 2002 and $3.757 million in 2003 for a total of $9.004 million for the latter two years.

Included among the various projects under the SFP umbrella were air conditioning upgrades and replacement; ADA upgrades; fire, life, and safety upgrades; electrical and telecommunications infrastructure upgrades; and reconfiguration of the GO1 building from hard wall offices to an open landscape office environment to facilitate and reduce the cost of employee moves.

ORA believes that some of the SFP costs included in SCE's forecast of capital costs for 2002 and 2003 are excessive and redundant, and that SCE may be seeking duplicate recovery for certain security enhancements. ORA also questions the reasonableness of SCE's decision to reconfigure GO1 to an open landscape environment. ORA recommends disallowance of the entire $9.004 million amount of SFP capital additions forecast by SCE for 2002 and 2003. In addition, ORA recommends disallowance of the costs of a new corporate fitness center that was included with the SFP. We address this latter recommendation in the following section.

***Discussion***

As shown in SCE's direct testimony (Exhibit 46, p. 44, Table VIII-7), expenditures on the first, third, and fourth floors of the GO1 building account for all of the $9.004 million in SFP expenditures that SCE forecast for 2002 and 2003. Most of the $41.346 million in planned spending on SFP projects, including $7.526 million for air conditioning chillers, occurred prior to 2001. Since the GO air conditioning chiller project was funded with expenditures made prior to 2001, and, except for the fitness center, ORA's SFP recommendations pertain to forecast expenditures for 2002 and 2003, we are perplexed by SCE's persistent attempts to show that ORA misunderstands the importance of the chillers. In fact, ORA does not recommend any disallowance with respect to the chillers.

A major focus of ORA's concern regarding the SFP pertains to the reconfiguration of GO1 to an open environment. However, SCE's direct testimony adequately addressed the value of this SFP component by noting the reduced cost of employee moves. In 1997 an average of 1,184 employees moved per year in GO1 at a cost of approximately $2,500 per move, or $2.96 million annually. With the reconfiguration, SCE expects the future average cost per move to be $400. SCE also expects the reconfiguration to improve the utilization of available space at the GO complex.

ORA also expressed concern regarding expensive artwork in the GO complex, based on observations by ORA's witness during a field trip. While we would be reluctant to have ratepayers fund expensive artwork, ORA's concern is not backed up by information or analysis that would allow us to determine the extent, if any, to which SCE's GRC request includes unreasonable costs for such funding. There is no evidence with respect to this issue that justifies a disallowance.

SCE demonstrated that its 2002 decision to earmark $4.5 million from the Various Major Structures blanket work order for certain security related improvements is separate from and addresses different requirements than those that the SFP improvements were intended to address. Thus, ORA has not demonstrated that its redundancy concerns are applicable to the SFP. We will further address this concern in connection with the blanket work orders, below.

Notwithstanding SCE's diversion to the issue of the chillers, SCE has demonstrated that the company's forecast SFP capital expenditures for 2002 and

2003 are reasonable. ORA's recommended disallowance of the forecast SFP capital expenditures for 2002 and 2003 will not be adopted.

#### 6.4.2.3.2. Corporate Fitness Center

As part of the SFP, SCE constructed a corporate fitness center, opened in 1999, for use by all GO occupants as well as employees that work at other locations. The objectives of the fitness center are to increase the number of employees who engage in regular physical activity and to leverage the knowledge and expertise of the fitness center staff across the company by expanding health education to address emerging health and safety issues such as back injuries, stress reduction, ergonomics, and nutrition education. SCE believes that meeting these objectives will lead to reduced absenteeism, increased productivity, and reduced work-related injuries. SCE also believes that it will assist in the attraction and retention of productive employees. The cost of the fitness center was $1.530 million. (Exhibit 302, p. 193.) SCE's Human Resources Department is responsible for operating the fitness center, the operating costs of which are addressed within Section 6.7.

ORA believes that the costs of the fitness center should not be funded by ratepayers, and it recommends removal of those costs for ratemaking purposes. ORA notes that SCE did not request prior Commission approval to construct the center. ORA also notes that SCE employees can enroll in private fitness programs and receive reimbursement through SCE health benefits that are also funded by ratepayers. ORA believes that shareholders benefit from healthy and productive employees, as expenses for sick and injured employees are reduced.

***Discussion***

ORA has not demonstrated that there are regulatory requirements that SCE secure Commission approval prior to constructing a corporate fitness center.

SCE's failure to do so is not a reason for disallowance of the center's costs. Nevertheless, we are not convinced that ratepayer funding of the center is necessary or appropriate at this time. We do not doubt that there are productivity benefits from having healthy employees. However, SCE has not adequately demonstrated that ratepayer funding of the fitness center represents a cost-effective means of improving employee health and producing productivity gains that benefits ratepayers.

SCE's health benefits program already provides full time employees who choose to enroll in a medical plan a Preventive Health Account, which provides reimbursement of up to $150 per year for completing approved fitness, diet, nutrition, smoking cessation, and other health promotion programs. Approximately 250 participants use the fitness center each day, which means that most of SCE's 12,000 employees either choose not to use it or are unable to do so. If the ratepayer benefits of the corporate fitness center were as demonstrable as SCE implies (but fails to demonstrate) they are, then we would need to consider significant disallowances in this GRC for SCE's failure to construct enough fitness centers, or provide comparable access to fitness facilities, so that all employees had access to their benefits.

Because SCE has not demonstrated that ratepayer funding of the corporate fitness center is reasonable, the associated construction costs should not be included in rate base.

#### 6.4.2.3.3. Seismic Upgrades

SCE's GO complex is within one mile of the epicenter of the 1987 Whittier Narrows earthquake. SCE's shared services capital request includes a forecast of $1.5 million in expenses in 2003 for seismic upgrades to GO2. This building was constructed in 1974 to accommodate computing / information services requirements. Lessons learned from the 1994 Northridge earthquake indicated that welded moment-frame buildings similar to the GO2 office area had sustained severe cracking in the beam-column connections. To minimize structural damage during moderate earthquakes, the seismic upgrades will add diagonal bracing. The upgrades will also include ceiling system bracing, anchoring and cross-bracing computer access floors, bracing partition walls, and installation of seismic bracing on pipe and duct supports and equipment.

ORA proposes a disallowance of the entire $1.5 million in capital expenditures for the seismic upgrade project. ORA did not discuss the reasons for its proposed disallowance in its prepared testimony. On cross-examination, ORA's witness suggested that SCE's decision to construct a corporate fitness center indicated that the seismic upgrades project was not a priority for SCE.

***Discussion***

SCE's decision to seismically upgrade its GO2 building was the result of a study conducted by the SAC Joint Venture, a partnership of the Structural Engineers Association of California, Applied Technology Council, and California Universities for Research in Earthquake Engineering, under contract with the Federal Emergency Management Agency (FEMA). The findings and recommendations were published in June 2000, whereas the corporate fitness center was completed in December of 1998.

SCE's decision to construct a fitness center has no bearing on the reasonableness of the proposed expenditures for GO2 seismic upgrades, and ORA has presented no other reason why the upgrades are unreasonable or imprudent. We find no basis for concluding that the seismic upgrades were not a priority. ORA's proposed disallowance will not be approved.

#### 6.4.2.4. Blanket Work Orders - Major Structures

Despite routine preventative maintenance and planned capital repairs and replacements, there are times when unplanned major structure work must be undertaken. In 1997 SCE established blanket work orders for “Various Major Structures” to provide funding for such occurrences. The budgeted funds have historically been required in each year since 1997, except for 1998. An example of their use is an upgrade to the overloaded electrical system of the Long Beach Telephone Center in 2000.

SCE’s request in this GRC includes $10.498 million for Various Major Structures. ORA recommends a complete disallowance of SCE’s $10.948 million forecast for Various Major Structures. ORA’s testimony states that:

> ORA believes that some of the costs SCE has forecasted relating to its implementation of its SFP are excessive and redundant. For example, SCE forecasted $10,948,000 for Various Major Structures, however SCE only briefly describes projects amounting to $4,500,000 of the $10,948,000 for security improvements and remains silent on its forecasts for the difference of $6,448,000. SCE forecasted an additional $1,471,000 for Security System Enhancements and another $1,288,000 for Access/Intrusion Security Control and some of the security line items listed in the forecasts for the three areas mentioned above appear to be some of the same or similar items and are thus redundant and not prudent investments, and should not be funded 100% by its ratepayers. (Exhibit 188, p. 16-D-3.)

***Discussion***

ORA’s proposed disallowance for Various Major Structures appears to be based upon a misunderstanding regarding the SFP and its relationship to blanket work orders. In fact, the SFP is a separate, specific project of defined purpose and duration, whereas the Various Major Structures blanket work orders provide funding for unplanned occurrences on an ongoing basis. SCE has demonstrated that there is no redundancy warranting their disallowance, and ORA has provided no other basis for its proposed disallowance. We therefore adopt SCE's request for Various Major Structures.

### 6.5. Information Technology

#### 6.5.1. Introduction

SCE's Information Technology (IT) Department oversees SCE's infrastructure of large processors, storage media, communications links, operating system and application software, and personal computing and communications devices. As of January 31, 2001, the IT Department had 1,056 regular and part-time employees and 208 supplemental and contract employees.

#### 6.5.2. IT Expenses

As set forth in its direct testimony (Exhibit 47, pp. 1-2), SCE forecasts test year IT O&M expenses of $117.891 million, consisting of $32.073 million in non-A&G Accounts 517, 561, 588, and 903, and $85.817 million in A&G Accounts 920/921, 923, 926, and 931. SCE states that while recorded expenses were an important starting point for the forecasting analysis, its test year O&M forecast is not based solely on past spending. SCE states that it also considered new and changing business requirements and the collective judgment of its IT experts. In other words, SCE used a budget-based approach for its IT O&M forecast.

ORA rejects this approach. Based on proposed adjustments to remove from recorded data the costs of a large (O&M expenses of $42.987 million in 1998, 1999, and 2000), nonrecurring IT project that addressed anticipated Y2K computer problems, and use of a five-year average of the resulting recorded/adjusted IT O&M expenses, ORA proposes an IT O&M forecast of $99.324 million. This represents a reduction of $18.566 million from SCE's aggregate forecast of $117.890 million for test year 2003 IT O&M expenses.

***Discussion***

SCE's forecast of $117.890 is $27.485 million (30.4%) higher than the 1996 recorded level of $90.405 million, and $6.055 million (5.4%) higher than the 2000 recorded level of $111.835 million. SCE states that two factors explain the increase from 1996 to 2003. First, the company decided "to retain and improve [its] in-house IT function," so it "developed and implemented several new practices (such as company wide planning, management of cross-business-unit-issues, adoption of common application development and maintenance processes and practices, and the establishment of common IT infrastructure hardware)." (Exhibit 47, pp. 25-26.) "Second, critical systems, such as CSS, were implemented during this time frame that required incremental application maintenance expense to support these systems on an ongoing basis. The increase in O&M expenses reflects our consolidation of IT application and development resources that were previously decentralized in our internal Business Units in the 1995 GRC." (*Id.,* p. 26.)

Such generalities and jargon may convey the sense that the IT department conducts many important functions, but they hardly explain, let alone convincingly so, why SCE was able to deliver IT services for $90 million in 1996 but requires almost $118 million in 2003 for IT O&M. Why is retaining and improving the in-house function so expensive, yet so beneficial? Why are new systems necessarily more expensive, yet indispensable to the provision of utility service? Even if new systems bring incremental costs, are there no offsetting decremental expenses from cessation of old ways of doing things? Why do ratepayers benefit from the centralization of resources if it costs so much? We cannot say for certain that the answers to these questions could not eventually be uncovered by line-by-line analysis of SCE's 275 pages of prepared direct testimony plus attachments on IT O&M and capital expenditures. Nevertheless, a proposed increase of such magnitude, unaccompanied by a clear and cogent statement of the reasons for the increase, calls into question the appropriateness of the budget-based forecasting methodology. SCE essentially asks us to approve its budget-based forecast on the basis of full faith in the knowledge and expertise of its IT professionals. We are unwilling to do so, and will therefore join ORA in basing the test year forecast on historical spending patterns.

SCE takes issue with the qualifications of ORA's witness to address the IT forecast based upon the fact that ORA did not demonstrate particular expertise or knowledge in the IT field. However, it is up to SCE to demonstrate the reasonableness of its forecast. If a qualified expert ratemaking witness can demonstrate flaws in SCE's showing that cast doubt on the reasonableness of that showing, then there is no reason to cast aside the recommendations of that witness simply because he is not a full time IT professional. If anything, the inability of SCE's IT witnesses to articulate in lay language the reasons for a proposed 30% increase above 1996 O&M spending is more problematic than ORA's failure to put IT professionals on its payroll.

A central issue is whether $42.987 million in Y2K project costs should be removed from the recorded data before a five-year average is calculated. SCE's argument is that it temporarily reprioritized other work when the Y2K project was underway, and that such work must now be done. ORA counters that Y2K expenditures should be removed because of the abnormal, nonrecurring nature of the project. ORA does not accept the contention that the deferral was temporary. In effect, ORA is saying that just as the Y2K project was undertaken in 1998, O&M expenses for other non-Y2K work were reduced by the same amount on a permanent basis. While such a reduction is not implausible, SCE has demonstrated that the deferral of work on governance activities such as company-wide IT planning, and other activities, is not sustainable going forward. We will not adopt ORA's proposed Y2K adjustment.

As shown in Table 14-E-2 of Exhibit 114, recorded IT O&M expenditures during 1996-2000 totaled $539.606 million, or an average of $107.921 million per year. We will adopt this five-year average as the forecast for IT O&M expenses in lieu of either SCE's or ORA's forecast. We will allocate the resulting $9.969 million reduction from SCE's forecast to Accounts 920/921, 926, 588, and 903 as proposed by ORA.

SCE noted that this allocation approach does not allow the traditional use of separate labor and non-labor escalation factors to the adopted constant dollar amounts in order to escalate 2000 constant dollar data to a 2003 basis. However, the Joint Comparison Exhibit shows that the parties have agreed that the disputed amounts can be categorized as non-labor (Exhibit 403, pp. 355-358.) We will escalate these accounts to 2003 by applying the non-labor escalation factors.

#### 6.5.3. IT Capital Expenditures

As set forth in its direct testimony (Exhibit 47, p. 3), SCE estimated cumulative IT capital expenditures of $148.334 million over the period 2001-2003 ($33.870 million for 2001, $47.062 million for 2002, and $67.402 million for 2003). These expenditures consist of (1) upgrades and replacements of personal computers, servers, and mainframe ($66.352 million), (2) upgrades and replacement of wires, communications, and support equipment ($35.145 million); (3) other major projects ($25.630 million); (4) minor projects and blanket purchase orders ($14.614 million); and (5) a Disaster Recovery Program ($6.593 million).

ORA took issue with SCE's proposed capital expenditures in the Blanket Budget Items category only, and only for the year 2003. ORA used average annual recorded capital expenditures for 1996-2000, excluding $25.107 million for Y2K related expenditures, to arrive at a forecast of $49.642 million in 2003, or $17.759 million less than SCE's IT capital expenditures forecast of $67.401 million for 2003.

***Discussion***

As with the forecast of IT O&M expenditures, the issue of IT capital expenditures involves disputes over whether to exclude Y2K related capital expenditures from recorded data, and whether to use a budget based approach or an average of recorded/adjusted data to forecast 2003 capital expenditures. Since the issue pertains to Blanket Budget Items, we will focus on that category of capital additions. Blanket Budget Items are routine, ongoing capital projects, with no single completion date, that provide for the expansion, replacement, and upgrades of the IT infrastructure.

ORA's case for excluding Y2K related costs from recorded capital expenditure data is no more compelling than it was for excluding Y2K related expenses. Although SCE was able to temporarily delay a portion of these ongoing projects to offset Y2K costs, continuing to delay this work is not sustainable, and could impact the company's ability to serve ratepayers. We will not adopt ORA's proposed Y2K adjustment to recorded IT capital expenditures.

At the same time, SCE's budget based approach relies on our willingness to accept the contentions of SCE's IT witnesses that the various ongoing projects will be carried out as planned despite the company's ability to defer the projects temporarily (as was done for the Y2K project). We do not doubt that each planned project in the Blanket Budget Items forecast was developed by IT personnel who understand the specific technical requirements for each item and who analyzed the needs of SCE's operating departments. However, the historical spending pattern (including Y2K expenses) shows that nominal capital expenditures for this category were $27.869 million, $33.489 million, $58.399 million, $46.203 million, and $33.580 million in the years 1996 through 2000 respectively, or an annual average of $39.908 million (nominal dollars). SCE is forecasting $52.646 million, or nearly 32% more than this five-year average. Along with the capital spending flexibility exhibited by the yearly variations and the deferrals due to Y2K activities, this calls into question the reasonableness of relying solely on spending plans to forecast capital expenditures for blanket budget items. We will therefore use a five-year average as proposed by ORA, as historical spending patterns reflect a willingness and ability to carry out spending plans. This results in an adopted reduction of $17.759 million to SCE's IT capital forecast.

#### 6.5.4. Y2K Retention Bonuses

SCE paid $547,965 in retention bonuses in 2000 to six employees involved in Y2K project. ORA contends these costs are non-recurring and should be removed from SCE's recorded base. Since 65% of this cost was expensed and 35% was capitalized, the recorded base for expenses (Account 920) would be reduced by $356,177 and the recorded base for capital (Account 101) would be reduced by $191,788.

***Discussion***

SCE contends that in recommending this adjustment, ORA implicitly assumes that SCE will not have any additional projects, like the Y2K project, requiring retention of critical IT talent with specialized technical skills needed for future IT projects. However, SCE has not demonstrated that it is necessary to expect to routinely pay certain IT employees an average bonus of nearly $100,000 for unspecified future projects. ORA's proposed expense and capital adjustments to remove the costs of these bonuses will be adopted.

#### 6.5.5. IBM Charges

SCE paid $112,388 to IBM Corporation for professional services rendered to assist in the initial development of an e-business strategy that set the tactical and strategic direction and overall vision of the IT business unit. ORA recommends that this expense be removed from Account 923 because the service was performed once and is nonrecurring.

***Discussion***

The e-business strategy originally developed with this work by IBM is still evolving as with all internet related initiatives. SCE will incur as much as $112,388, if not more, in the 2003 Test Year for this initiative to refresh these strategies and determine what revisions are necessary due to industry changes that will occur in the e-business environment. ORA's proposed adjustment for IBM charges will not be adopted.

### 6.6. Capitalized Software

Under the terms of a settlement agreement adopted by D.92-11-051, SCE was authorized to capitalize application software development costs amounting to $100,000 or more for projects with a useful life of at least five years. SCE capitalizes only software projects over $1 million. SCE forecasts a total capitalized software rate base for the test year of $222.982 million.

SCE requests $31.862 million in direct additions for 2002 and $40.754 million in additions for 2003. ORA accepts SCE's request for 2003 but recommends removal of $860,000 from 2002 additions for contingency for SCE's Outage Management System Enhancement (OMSE).

***Discussion***

SCE included a $1.28 million contingency in the OMSE estimate. Of this amount, $420,000 was for unforeseen hardware (capacity and storage) needs, which ORA finds reasonable. ORA takes issue with the remaining $860,000, alleging SCE has not provided adequate support. Reviewing an article by William H. Roetzheim, author of the book *Software Project Cost and Schedule Estimating – Best Practices*, who SCE relied upon in part to justify its proposed contingency, ORA concluded that SCE's rationale for including the $860,000 was not persuasive. ORA believes that Roetzheim has indicated that contingencies can be positive or negative.

SCE has shown that the $860,000 contingency for software was based on industry standards and best practices for application development, which indicate including a contingency in budgeting for capitalized software projects. This contingency is actually 8.4% of the total software costs. When the OMSE contingency was developed, the project was in the design phase, for which the industry literature indicates a 10% contingency is appropriate. ORA's proposed reduction will not be approved.

## 6.7. Human Resources (HR)

### 6.7.1. HR Departmental Costs

#### 6.7.1.1. Total Compensation Division

SCE forecasts $4.823 million in A&G expenses in Accounts 920, 921, 923, and 926 for the Total Compensation Division of the HR Departmental Organization. This is composed of $3.206 million for labor and $1.617 million for non-labor. Within Account 920/921, SCE forecasts non-labor expenses of $63,000, based on a three-year average (1998-2000). ORA proposes a $33,000 reduction to the Total Compensation Division's non-labor expenses in FERC Account 921, based on the last recorded year's expenses.

***Discussion***

The recorded non-labor amounts in Account 921 for the Total Compensation Division are shown in the following table:

**Total Compensation Division**
**FERC Account 921 Non-Labor**
**(Constant Dollars X 1000)**

| 1996 | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|
| 735 | 116 | 73 | 87 | 30 |

SCE selected a three-year average of $63,000 after determining that a four- or five-year average would overstate expenditures due to the inclusion of 1996 and 1997 costs which reflect higher than anticipated use of supplemental workers. ORA believes that the 2000 recorded spending level provides the best forecast because costs have been declining every year and because ORA did not believe that SCE provided adequate documentation for the forecast increase of $33,000 above the year 2000 level.

We find SCE's proposal to use a three-year average to be reasonable because it normalizes for yearly variations. The last recorded year is the lowest value of the five years from 1996 to 2000, but that alone does not indicate that it is a reasonable predictor of test year expenses. We therefore adopt SCE's forecast.

#### 6.7.1.2. HR Service Center

##### 6.7.1.2.1. Dues and Memberships

ORA made a normalized adjustment of $53,000 to Account 921 to remove the costs of dues and memberships that, ORA contends, do not relate to the utility business. The dues and memberships at issue are for such organizations as the Corporate Executive Leadership Board, the Academy of Business Leadership, the Human Resource Planning Society, the American Statistical

Association, and Inroads, a trade and technical association. Because of the use of a four-year average, this results in a proposed $13,000 reduction to FERC Account 921.

***Discussion***

This dispute turns on whether the dues and memberships at issue are related to the provision of utility service. In SCE's 1995 GRC decision, the Commission addressed dues and memberships in Account 921 as follows:

> We have a long-standing policy not to allow recovery in rates of dues to chambers of commerce and service clubs. In *Pacific Tel. & Tel. Co. v. Public Util. Comm.* (1965) 62 Cal.2d 634, 669, the California Supreme Court upheld this policy. We apply this policy here and grant DRA's recommendation not to fund $82,000 for chamber of commerce dues. We also concur with DRA's second recommendation [not to fund $19,000 for certain membership dues] because Edison did not meet its burden of proof in demonstrating how these organizations relate to the utility's business and offer ratepayer benefits. (D.96-01-011, 64 CPUC2d 241, 316.)

Thus, it should have been clear to SCE that it needed to sustain its burden of proving that the dues and memberships at issue offer ratepayer benefits. SCE's brief does not point to any portion of SCE's direct showing where such proof is provided. SCE focuses on the fact that it is not seeking ratepayer reimbursement for chamber of commerce or service club dues, but the point of the foregoing passage is not that all memberships and dues are recoverable from ratepayers so long as they are not for chambers of commerce or service clubs. SCE must show that any memberships or dues for which rate recovery is sought offer ratepayer benefits. SCE's rebuttal testimony (Exhibit 302, p. 120, line 1 through p. 124, line 4) addresses this issue, but as noted elsewhere this is improper litigation, and we therefore strike that testimony.

Because SCE has failed to meet its burden of proving that the memberships and dues at issue offer ratepayer benefits, ORA's proposed reduction of $13,000 is adopted.

#### 6.7.1.2.2. FERC Account 923

SCE records outside services costs associated with strategic and operational change initiatives to FERC Account 923 in the HR Service Center. SCE used a four-year average of 1997-2000 recorded amounts to estimate test year expenses of $427,000 for the HR Service Center in Account 923, whereas ORA proposes a five-year average of the years 1996-2000 to arrive at a forecast of $342,000. This results in a difference of $85,000.

***Discussion***

The recorded non-labor amounts in Account 923 for the HR Service Center are shown in the following table:

**HR Service Center**
**FERC Account 923 Non-Labor**
**(Constant Dollars X 1000)**

| 1996 | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|
| 2 | 347 | 98 | 676 | 587 |

In 1996, SCE implemented a company-wide workforce reduction effort and HR curtailed activities relating to strategic and operational change initiatives. Moreover, 1996 was a start-up year for the HR Service Center. We conclude that the test year forecast should not be based on consideration of 1996 data. ORA's proposed reduction will not be approved.

#### 6.7.1.3. Outside Services for Executives

SCE used a three-year average to estimate costs for outside services for executive in Account 923 to arrive at a forecast of $1.066 million. ORA used a five-year average to arrive at a forecast of $787,000, which is a proposed reduction of $279,000. ORA noted that SCE did not substantiate how ratepayers benefit from an increase in outside services for executive studies and compensation statements that “increase executive understanding and appreciation of the compensation benefits they receive.”

***Discussion***

Outside services that help executives understand and appreciate their compensation benefits are, at best, of questionable value to ratepayers. We note that SCE does not contest ORA’s proposed reduction, which is hereby adopted.

### 6.7.2. Employee Compensation Issues

#### 6.7.2.1. Total Compensation Study

In accordance with Commission direction in prior GRCs (D.87-12-066, D.91-12-076, and D.96-01-011), SCE and ORA jointly selected an independent expert, Hewitt Associates, to perform a total compensation study. SCE and ORA jointly managed the study. In the context of this study, “total compensation” represents cash (including base salaries and annual incentive compensation) and non-cash compensation (i.e., pensions and benefits) received by SCE’s workforce.

Based on samples of job categories representing 41% of SCE’s workforce of 12,818 employees, the study shows that SCE’s aggregate compensation is 4.3% above market levels. However, the sampling error is plus or minus 5%. The Hewitt study results are summarized in the following table:

**Summary Results of Total Compensation Study**
**(Percentage above/below market)**

| Job Category | Base | Base plus | Benefits | Total |
|---|---|---|---|---|

| | **Salary** | **incentives** | | |
|---|---|---|---|---|
| Physical/technical | 5.1% | 1.6% | 7.8% | 2.6% |
| Clerical | -1.7 | -1.3 | 10.6 | 0.8 |
| Professional/technical | 3.2 | 6.8 | 14.3 | 7.9 |
| Managerial/supervisory | 1.4 | 3.1 | 0.2 | 2.7 |
| Executive | -0.4 | -3.5 | 30.3 | -1.1 |
| Overall | 2.6% | 3.4% | 9.3% | 4.3% |

ORA and Greenlining addressed aspects of the total compensation study in their opening briefs, as described below.

***Discussion***

The submission of the total compensation study comports with prior Commission directives. We appreciate SCE's and ORA's cooperative efforts in this respect. Since SCE's total compensation is shown to be 4.3% above the comparable market total compensation, and the study margin of error is plus or minus 5%, we conclude that SCE's total compensation for all employees is equivalent to the market level as the market is defined in the study.[46] We will not make a ratemaking adjustment on the basis of above market total employee compensation.

ORA states that because the total compensation study shows that SCE's overall total compensation is 4.3% above market, and ORA does not object to such above market payments to labor, this represents a major concession to SCE worth millions of dollars. However, as noted previously, we cannot conclude

[46] It is more technically accurate to state that SCE's total compensation may be above market as defined in the study, but we cannot rule out the hypotheses that it is at or even slightly below market.

with certainty that SCE's compensation, on an overall basis, is above market because of the margin of error in this study.

Greenlining, which indicates it is concerned with excessive executive compensation, believes that the total compensation study presented in this proceeding is of limited value with respect to executives because, according to Greenlining, it is predicated upon comparisons with inflated compensation packages. We share Greenlining's concern about our ability to make a meaningful assessment of executive compensation levels based on the current study. We want to ensure that SCE is positioned to provide safe, reliable public utility service to its customers. This requires that SCE be able to attract, retain, and motivate qualified employees, including employees in the management and executive ranks, which means it needs to be a competitive employer. However, we are also interested in protecting ratepayers from excessive costs. We look to market comparators to determine the level of employee total compensation needed to provide reasonable assurance that SCE is a competitive employer that is not providing above-market salary / benefit packages that would add unnecessarily to ratepayer costs.[47] An appropriately-designed total compensation study should allow us to do that.

SCE and ORA, along with Hewitt, have fulfilled the Commission's directives in earlier decisions, and have provided us with a sufficient basis for approving the ratepayer contributions to executive compensation for the purposes of this decision. However, SCE should strive to improve its point-of-

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[47] Greenlining witness Gamboa acknowledges that "compared to corporate America generally, the Edison [executive] compensation packages do not appear to be excessive." (Exhibit 268, p. 7.)

comparison for future rate cases.The Hewitt Study (Exhibit 77) looks at both a cluster of other energy utilities and a group reflecting “general industry,” the latter composed almost entirely of unregulated firms. Greenlining questions the appropriateness of comparing the compensation of SCE executives to that of executives from the particular non-utility firms included in the Hewitt Study. The 27 firms include Bechtel, Boeing, Enron, Farmer’s Insurance, Honeywell, Nestle USA, Unocal and Western Digital Corporation.[48] According to Hewitt, it selected these companies because they are major California employers, and because some of them are based in Southern California.

Our concern with this approach is broader than issues related to the particular firms selected. The Commission’s decision about the appropriate level of executive compensation to include in rates must be informed by recognition of the public interest and appropriate public policy. Reliance on a comparison with the compensation for executives in general industry does not recognize that those leading a regulated utility business are vested with a public trust.

While such executives deserve to earn adequate compensation, the utility must provide, and we must ensure, that such compensation does not extract excessive sums from captive customers. The utilities are obligated to create an environment in which all utility workers can be productive and motivated. Michael Phillips, testifying for Greenlining, asserts that company-wide efforts to cut costs are unlikely to be successful where the majority of workers believe that top executive compensation packages or bonuses are inconsistent with the need

[48] The original “general industry” cohort included a 28th firm, the Walt Disney Company. Hewitt chose to omit Disney for the purposes of the executive compensation survey.

for cost-cutting, or may be the only reason why cost-cutting is necessary. While we do not conclude, based on the record before us, that SCE executives receive excessive compensation, it is reasonable to expect that a very large disparity between executive and rank-and-file compensation packages could undermine morale, and ultimately the effectiveness of the entire enterprise. It is not evident that the Hewitt general industry firms are screened for these purposes, nor that one could effectively reflect this interest when comparing utility compensation with that in unregulated firms.

Hewitt does balance its general industry cohort with one composed of 18 utility firms with $1 billion or more in annual revenues. With the exception of Sempra Energy and Pacific Gas and Electric Company, these utilities are all located outside of California. They include Duke Energy, Florida Power & Light, PECO Energy Company, Consolidated Edison of New York, among others. On the record before us, we lack a basis for determining if these firms provide a meaningful comparison, because we know little about their specific compensation practices. Perhaps the most instructive comparison would be to the compensation for executives of the Los Angeles Department of Water and Power and the smaller municipal utilities in Southern California. These are executives who have been attracted to jobs running other successful electric utility businesses in the vicinity of SCE, and who most likely have the opportunity to live in similar places. Yet, the Hewitt study in its current form does not consider such other utilities. We direct SCE to begin efforts, now, to develop a compensation study more consistent with the concerns we discuss, above.

Greenlining also asks that we adopt a requirement that SCE report annually on the total compensation packages for each of the top ten executives, including the value of stock options and retirement plans. This information would be instructive as part of the Commission's effort to better understand the nature of SCE's executive compensation practices. We will adopt this requirement.

#### 6.7.2.2. Executive Compensation

##### 6.7.2.2.1. Executive Bonuses

SCE's request for executive salaries in Account 920 includes the costs of incentive compensation received by executive officers. Based upon its position that ratepayers and shareholders should contribute equally to the costs of executive bonuses, ORA recommends that SCE's forecast be reduced by one-half the costs of such bonuses, or $2.358 million. SCE opposes this recommendation.

***Discussion***

SCE states that the total compensation study shows that total compensation for the executive category is 1.1% lower than competitive market norms. As a preliminary matter, we note that in making this statement, SCE commits the same error it accused ORA of committing when ORA said that SCE's overall total compensation is 4.3% above market. If the study's margin of error does not permit ORA to make such a statement, it also does not permit SCE to claim that its executives receive less than competitive norms. In fact, we cannot rule out the possibility that SCE's executives receive above market total compensation. Nevertheless, neither the total compensation study nor any other record evidence provides us with any basis for concluding that SCE's executive total compensation, including base salary, incentive pay, and non-cash compensation, is unreasonable. At issue is which of differing policies regarding ratepayer funding of incentive programs that have been applied in the past should be pursued here.

The approach favored by SCE is that adopted in GRCs of PG&E and SoCalGas in 1992 and 1993, respectively. In D.92-12-057, the Commission noted the following conclusions of a workshop conducted by the Commission staff:

> "The consensus reached in the workshop was that the Commission should not attempt to micromanage utility incentive compensation programs. Instead of adopting a 'cookie cutter' approach, workshop participants recommend that the Commission review incentive compensation programs utility by utility, as a component of the total cash compensation requested in each utility's general rate case. They proposed, moreover, that the allocation of total cash compensation between salaries and incentives should be left to each utility's discretion." (47 CPUC 2d 143, 201.)

The Commission stated that these conclusions "make it clear how the issue of incentive compensation programs should be handled." (*Id.*) It also stated that "we find in this proceeding that the [Performance Incentive Plan (PIP)] program as PG&E has designed it is an appropriate part of the total cash compensation which we have already found to be reasonable." (*Id.*, 203.)

The Commission reached a similar result in D.93-12-043, in SoCalGas' 1994 GRC, notwithstanding the conceptual concern that the SoCalGas incentive program may not motivate executives to exceed expectations:

> On the other hand, the incentive program appears to be part of a package of compensation benefits offered to SoCalGas executives. In D.92-12-057, we found that incentive compensation should be analyzed as "part and parcel of the overall compensation scheme," and that "the allocation of total cash compensation between salaries and incentives should be left to each utility's discretion." Including incentive compensation amounts in SoCalGas's total budget for executive compensation does not move that budget out of line with executive compensation packages for other California utilities. If, in the future, management incentive awards would push executive compensation levels out of the range offered by comparable utility

> companies, we will not hesitate to disallow them. (52 CPUC 2d 471, 496.)

ORA favors the approach taken in other, more recent GRC decisions. In SCE's 1995 GRC the Commission followed the approach that it had taken in an earlier PG&E GRC:

> In PG&E's test year 1987 general rate case, even though we noted that PG&E's executive compensation (including its proposed incentive plan) is commensurate with levels paid by utilities of comparable size, we concluded that a 50/50 sharing of the cost of its incentive plan was reasonable, stating that "we find merit in the staff argument that if PG&E's executives perform well enough to justify the 'bonus' then there should be enough savings to pay for the" incentive plan. (D.86-12-095, 23 CPUC 2d 149, 187.) We think a similar approach is appropriate here. (D.96-01-011, 64 CPUC 2d 241, 368.)

In PG&E's test year 1996 GRC, the Commission found that only 50% of the costs of PG&E's Management Incentive Program should be allowed. (D.95-12-055, 63 CPUC 2d 570, 592. In PG&E's test year 1999 GRC, the Commission again allowed 50% ratepayer funding of PIP incentives. (D.00-02-046, mimeo., p. 259.) In the latter decision, the Commission noted that continuing the practice of 50/50 sharing mitigated the concern of overcollection that could occur if the employees failed to perform well enough to earn targeted PIP payouts.

Acknowledging that the Commission has decided these issues differently over the years, SCE submits that its favored approach of full ratepayer funding should be approved because the Commission decisions that have adopted that approach were informed by the staff workshop process. SCE submits that the Commission got it right when deciding that as long as the total compensation package is reasonable, the allocation of that compensation among cash, benefits, and long-term incentives should be left to utility management's discretion.

There is no evidence in this proceeding that SCE's executive incentive plan produces inappropriate incentives or results in possible overcollections that would be mitigated by 50/50 sharing. The only evidence that speaks directly to the issue is the total compensation study, which shows that SCE's executive compensation, including annual and long term incentives, is at market levels subject to the study's margin of error.

If SCE had decided that the total cash compensation received by executives should be in the form of base salary without any incentive plan, there presumably would be no issue of ratepayer cost responsibility as long as total compensation for executives is at market levels. In the absence of any evidence that the executive incentive program itself produces outcomes that are contrary to ratepayer interests, we will not interfere with the utility's discretion to adjust the appropriate mix of base salary and incentives. ORA's proposed adjustment of $2.358 million therefore will not be approved.

###### 6.7.2.2.2. Executive Retirement Benefits

ORA recommends that the policy of 50/50 sharing of the costs of cash incentives for executives be extended to retirement plans. ORA therefore recommends that SCE's request for Supplemental Executive Retirement Plans be reduced by 21%, or $3.642 million.

***Discussion***

The total compensation study shows that SCE's total executive compensation, including the Executive Retirement Plan, is competitive with and does not exceed the relevant market level by more than the margin of error. Accordingly, and also because we are not adopting 50/50 sharing for executive cash incentives, we find no evidentiary basis for adoption of this proposed reduction.

#### 6.7.2.2.3. Executives and Philanthropy

Greenlining witness Gamboa does not suggest any curtailment of SCE's executive compensation packages or bonuses. (Exhibit 268, p. 7.) Nevertheless, he believes that the SCE executive compensation packages appear excessive when compared to SCE's philanthropic practices. (*Id.*, p. 8.) Greenlining witness Phillips also suggests a relationship between executive compensation and corporate philanthropic expenses:

> …[D]ue to the difficulties of analyzing executive compensation, it may be appropriate to compare it to corporate philanthropy since both are deductible expenses. What ratio is appropriate cannot be determined without further analysis. At a minimum, that analysis should also include the relationship of philanthropy to pre-tax income, as well as the relationship of executive compensation to pre-tax income. (Exhibit 269, p. 3.)

***Discussion***

It is clear that Greenlining's concern has more to do with philanthropy than it does executive compensation. During cross-examination, Greenlining witness Phillips agreed that the reasonableness of a utility's compensation should be based on a comparison of its compensation of other employers with which the utility competes for labor resources. (Tr. V. 38, p. 3456.)

The American Heritage Dictionary defines "philanthropy" as "the effort to increase the well-being of mankind, as by charitable donations." The Commission's policy of excluding charitable donations from authorized rate recovery was upheld by the California Supreme Court in *Pacific Tel. & Tel. Co. v. Public Util. Comm*. (1965) 62 Cal.2d 634, 669. The corollary of our policy to exclude expenses of utility philanthropic practices from rates is that this

Commission will not, as part of its ratemaking responsibilities, interject itself into utility management decisions regarding corporate philanthropy.

Greenlining acknowledges that "the Commission does not appear to have the explicit authority to require Edison to set goals with respect to philanthropy," but suggests that "the Commission may wish to encourage Edison to set its own internal goals by broadly and prominently noting in its decision Edison's poor philanthropic record, and the fact that the bonuses paid to the top ten executives vastly exceed Edison's contributions to the poor and to non-profits serving communities of color." (Greenlining opening brief, p. 8.) We decline to do so at this time. Whether or not SCE's corporate philanthropy practices are, as variously described by Greenlining, inexcusable, negligible, embarrassing, or unfocused, we have no jurisdiction to order changes in SCE's giving practices. At least for purposes of ratemaking, Greenlining's attempt to link SCE's executive compensation packages and its philanthropy is not supported by any study, and is without merit.

#### 6.7.2.3. Incentive Plans

##### 6.7.2.3.1. Spot Bonuses

SCE has several incentive / bonus pay programs, including the Spot Bonus program. Spot bonuses are lump sum cash awards that may be paid at any time by managers to recognize outstanding performance by an individual or a team. SCE paid spot bonuses totaling $5.589 million in 1999 and $4.246 million in 2000. ORA believes that the costs of the Spot Bonus program should not be borne by ratepayers, and recommends these amounts be removed from recorded data.

ORA opposes ratepayer funding of the Spot Bonus program because "[t]he nature of the program implies that the bonuses are associated with corporate goals and objectives," and "[r]atepayers are already providing for the employees wages and benefits and should not pay additional money for employees to do their required jobs." (Exhibit 116, p. 3-8.) ORA believes that "ratepayers should not pay for awards that are made at the discretion of management to meet its corporate objectives that increase shareholder value." (*Id.*)

***Discussion***

If it were shown that the Spot Bonus program does not result in employees receiving above-market total compensation, and that the program does not produce outcomes that are contrary to ratepayer interests, we would be inclined to include the program costs in the authorized revenue requirements.

With regard to the latter point, the record shows that the program is consistent with ratepayer interests, even if the program increases shareholder value. If anything, the evidence suggests that benefits of quickly restoring service during storm conditions, successfully managing T&D automation projects, and providing effective leadership can accrue to ratepayers and shareholders alike. Moreover, since awarding of a spot bonus for outstanding performance gives SCE's managers an alternative to raising an employee's base salary, the integrity of SCE's base salary system is kept intact, and the company's long-term salary and wage-based benefit costs are not increased. We note that spot bonuses are widely used by U.S. corporations.

With regard to the former point, SCE states that "SCE's total compensation includes a Spot Bonus program," (SEC opening brief, p. 181, and that "Spot Bonuses are an integral part of SCE's Total Compensation Program" (*Id.*, p. 184). However, even though SCE's total compensation package includes spot bonuses, for ratemaking purposes we are more concerned with the portion of total compensation that is measured in the SCE/ORA total compensation study. Since that study explicitly excludes spot bonuses (Exhibit 77, p. 12), we are in no position to conclude that the Spot Bonus program does not result in SCE's overall total compensation being above market level. Accordingly, we cannot conclude that the costs of the Spot Bonus program are reasonable. The costs will be removed from recorded years 1999 and 2000 as proposed by ORA. The test year impacts of removing these costs is shown in the Joint Comparison Exhibit (Exhibit 403, pp. 282-291.)

#### 6.7.2.3.2. Results Sharing

Another SCE incentive pay plan is the Results Sharing program, established in 1995. This program links compensation to employees' annual job performance, business unit, and Company performance. All full time employees are eligible to earn a cash bonus based on team (business unit or department) and SCE performance measured against stated goals. Depending on how well the business unit performs compared to its goals, salaried exempt employee can earn from 0% to 6% of their annual pay, and non-exempt employees can earn from 0% to 3% of their pay.

Once the applicable percentage of base pay is determined, it is multiplied by a corporate modifier, which reflects a comparison of operating income to corporate goals. The corporate modifier can range from 0.5 to 2.0. Thus, total Results Sharing awards will increase or decrease each year based on overall SCE business results. In 1999 the 2.0 modifier was applied, whereas in 2000, as the company faced a financial crisis, the operating income multiplier used to calculate results sharing was 0.50.

SCE claims that the Results Sharing program focuses on short- and long-term goals that both benefit ratepayers and make SCE successful. The goals include customer service, employee safety, cost savings, new ideas, teamwork, and innovation. SCE maintains that "a very substantial portion of [the] Results Sharing program is designed to benefit ratepayers." (Exhibit 53, p. 70.)

SCE used a hybrid of averaging and a budget-based approach to forecast test year Results Sharing program expenses. First, for the years 1997-1999, SCE calculated the three-year weighted average of the relationship between actual and maximum possible Results Sharing payout to determine an average payout factor of 87.2% that it "rounded" to 90%. SCE did not use 1996 because data were not readily available, and it excluded 2000 data because of the energy crisis. SCE next estimated what its 2000 Results Sharing payout would have been if not for the financial crisis that year. SCE actually paid out $20.5 million under the Results Sharing program rules, and it made a supplemental payment of $44.4 million in 2002 for a total Results Sharing payment for the 2000 program year of $64.900 million. Using the 90% average payout factor, SCE adjusted its recorded payout for 2000 to arrive at a recorded/adjusted payout of $75.965 million. SCE then used this figure to develop a unit cost per labor dollar for 2000. Finally, it applied this unit cost to the estimated labor dollars for 2003 to forecast Results Sharing program expenses of $80.884 million for the 2003 test year. This forecast is distributed among FERC Accounts 500, 588, 905, and 920.

ORA does not take issue with SCE paying its employees incentives for good job performance, but it believes that ratepayers should not pay 100% of the costs incurred for sizable bonuses. Using a five-year average of Results Sharing costs, ORA forecasts test year expenses of $58.172 million. Then, as it did with other employee incentive programs, ORA recommended 50/50 shareholder-ratepayer sharing of the expenses for this program. Thus, ORA recommends that $29.086 million be funded by ratepayers, which represents a proposed disallowance of $51.979 million.

***Discussion***

No party takes issue with the premise of the Results Sharing program or the idea that ratepayers should fund at least a portion of its costs. With the program's incentives, employees are motivated by the potential to receive higher pay to improve performance in areas such as safety, environmental compliance, customer satisfaction, and reliable service, and better performance in those areas is clearly in the best interests of utility customers. SCE's Results Sharing program thus better aligns the interests of its ratepayers and employees. The issues are the appropriate forecasting methodology and whether ratepayers should fund the full amount of the forecast expense. We first address whether SCE's hybrid forecasting approach or ORA's averaging approach yields the more reliable forecast of test year expenses.

ORA used a five-year average due to the fluctuations in recorded costs. Although such fluctuations might indicate the use of a five-year average in other circumstances, it is not appropriate to use a five-year average in this case because the program has changed considerably since its inception in 1995. Through collective bargaining, represented employees became eligible for Results Sharing program awards in 1999, and the number of eligible employees has nearly doubled. Also, the target and maximum payout percentages have changed. In 1996, the maximum payout for represented employees was $400, whereas in 1999 these employees had a maximum payout opportunity of 6% of pay, which equates to approximately $3,600 per represented employee. In 1998, target and maximum payouts increased. Plan design in 2003 and beyond is more likely to look like the 1999-2000 version of the plan than the plan in its early years.

On the other hand, SCE has not demonstrated the reasonableness of its estimation method. Neither SCE's direct testimony (Exhibit 53) nor its other, belated efforts (Exhibits 198, 302) adequately explain SCE's methodology, let alone its reasonableness. If year 2000 data were as inappropriate for use in averaging as SCE claims it to be, then we fail to see how SCE's convoluted adjustments using 2000 data would remedy the perceived problem.

We conclude that both SCE's and ORA's forecast methodologies yield questionable forecasts for Results Sharing program costs, and we therefore adopt an alternative method. Since the program did not evolve to its current configuration until 1999, we think it is most reasonable to utilize a two-year average of actual payouts for 1999 and 2000. The year 2000 may not be fully representative of the test year, but that is a reason to use an average, not a reason to exclude the data altogether. SCE has not shown that the lower payout for that year renders it inappropriate for use as part of an average, particularly in light of the supplemental payment of $44.4 million. SCE paid out $81.964 million in 1999 and $64.900 million in 2000. The two-year average is $73.432 million, which we adopt as the test year forecast.

We next turn to ORA's recommendation for 50/50 funding of the program. As noted earlier in connection with executive incentive compensation, the Commission has decided this issue differently in various GRCs over the past 15 years. In this case, we are satisfied that the company's total compensation program as measured in the total compensation study, including the Results Sharing program, does not exceed competitive employment market levels.[49] Therefore, there is no basis for concluding that the forecast of Results Sharing

[49] Unlike the Spot Bonus program, which was excluded from the total compensation study, the Results Sharing program was included. (Exhibit 77, pp. 4, 13.)

program costs is unreasonably high, at least on the basis of market levels of employee compensation.

We also note that it would be within SCE's managerial discretion to offer all cash compensation to employees in the form of base pay instead of a mix of base pay and incentive pay. In the event SCE were to do so, we would not take issue with ratepayer funding of the resulting compensation as long as total compensation is reasonable. If total compensation does not exceed market levels, a disallowance of reasonable expenses for the Results Sharing program would in effect be a substitution of our judgment for that of SCE managers regarding the appropriate mix of base and incentive pay. That is the sort of micromanagement that the Commission rejected in D.92-12-057, and that we reject here.

Moreover, there is no evidence that SCE's Results Sharing program creates outcomes that are contrary to ratepayer interests. SCE's direct showing demonstrates that the program is largely designed to benefit ratepayers as well as shareholders. Additionally, SCE's direct testimony (Exhibit 53, pp. 70-71) addresses the overcollection issue that was among the concerns that led the Commission to adopt 50/50 sharing in PG&E's 1999 GRC. The concern that full ratepayer funding of forecast Results Sharing program costs would provide SCE with an incentive to enrich shareholders is mitigated by the fact that the program has clearly stated business unit and employee goals. Whether the goals are met is largely within the individual and collective control of employees, not corporate officers.

We conclude that under the circumstances attendant to SCE's Results Sharing program, 50/50 sharing is not warranted, and full ratepayer funding of the forecast amount is justified.

#### 6.7.2.3.3 ACE Program

Another employee incentive program is SCE's "Awards to Celebrate Excellence" (ACE) program. The program provides recognition to employees who take action above and beyond normal work responsibilities that result in achieving critical targets such as providing excellent customer service. Recognition is provided by the awarding of points redeemable for merchandise. SCE's forecast includes $433,000 in ACE program costs in Account 926.

ORA proposes exclusion of ACE program costs on the grounds that they fall into the category of "social, cultural, and charitable activities" of the type for which the Commission has consistently denied rate recovery.

***Discussion***

SCE has demonstrated that the ACE program is neither a cultural nor a social activity, but is rather a tool to enhance employee performance. Since the program encourages employee performance that is consistent with ratepayer interests, and the use of formal recognition programs such as the ACE program is an established business practice for most companies, we will allow the inclusion of this modest employee benefit expense.

#### 6.7.2.4. Other Compensation Issues

##### 6.7.2.4.1. Pensions

SCE's retirement plan costs ranged from $49 million to $55 million (in nominal dollars) during the 1996-1999 recorded period. As a result of favorable investment experience during that period, the plan exceeded the IRS full funding limitation in 2000 and no tax-deductible contributions could be made.

SCE's forecast of retirement plan costs for the test year is $31.450 million. This forecast is based upon determinations made by the retirement plan actuary, AON Consulting. AON used the Frozen Initial Liability actuarial cost method, one of the methods allowed for pension funding under the Employee Retirement

Income Security Act of 1974 (ERISA), and the same method used in previous GRCs. ERISA also allows the actuary to use smoothing techniques for determining asset valuation in order to mitigate any wide swings in pension contributions from year to year that might result from volatility in financial market returns. AON used a four-year moving average of the actuarial value.

ORA contends that SCE's four-year moving average of the actuarial value of the plan assets chronically undervalues the plan's value. ORA found that from 1990 through 2001, the actuarial value was always less than market value, and it averaged 87.7% of market value. Over the last five years, the actuarial value averaged 82.2% of market value. ORA contends that this is unfair to ratepayers, and is evidence of bias in SCE's method. ORA also believes that SCE's method is volatile, as evidenced by the fact that fair market value dropped 21% in 1997 but SCE's actuarial value dropped 26%.

ORA recommends a four-year moving average of the actual fair market value of plan assets. ORA believes this is conservative because returns on assets exceed benefit payments. ORA also recommends using the minimum limit for ratemaking purposes because it is a measure of legal funding requirements and, according to ORA, is a more accurate and reliable measure of actual funding obligations. ORA's method produces a zero funding requirement for 2003 because expected plan assets of $2.936 million exceed accrued liability of $2.752 million at end-of-year 2003. Thus, ORA recommends a reduction of $31.450 million from SCE's test year forecast for Account 926.

***Discussion***

If sound actuarial practice indicates a funding level above ERISA minimum funding requirements, we favor a conservative policy of authorizing expenses for that larger funding level to avoid potential under-funding that could jeopardize the interests of either retirement system beneficiaries or future generations of ratepayers. In light of this policy, the issue in this GRC turns on whether ORA's approach is sufficiently conservative and in line with actuarial practice.

Even though the actuarial value of SCE's retirement plan has consistently exceeded the market value for several years, the ratio of actuarial to market value had risen to 96.2% in 2002 and was projected to be 112.0% in 2003. This is consistent with and corroborates SCE's contention that when investment returns are favorable, actuarial asset returns generally are, and should be, below market returns. Conversely, when investment returns are unfavorable, actuarial asset returns generally are, and should be, above market value. We therefore find ORA's claim of bias in SCE's valuation method to be unsubstantiated.

ORA's smoothing method not only smoothes investment returns, it also smoothes changes in market value attributable to employer contributions and benefit payments. SCE contends that this method is not usable either for ERISA minimum funding purposes or for IRS tax deductibility purposes, and ORA has not pointed to evidentiary support for the contrary position that it espouses. ORA points to a settlement agreement in another utility's proceeding in which the parties agreed to set rates on the basis of the actual market value method, but under our Rules of Practice and Procedure settlements are non-precedential. Also, ORA's reliance on a single year's data to show that SCE's smoothing method is more volatile than ORA's method is unpersuasive.

We note that while ORA claims that its methodology is better for ratepayer interests, ORA does not contend that SCE's methodology fails to meet all the criteria established by professional actuarial organizations and the IRS. We conclude that ORA's alternative valuation methodology lacks adequate evidentiary support, and therefore accept SCE's valuation methodology. Since the issue of pension funding in this GRC turns on the disputed methodologies, we therefore adopt SCE's proposal to include $31.450 million in pension funding in the authorized test year revenue requirement.

#### 6.7.2.4.2. 401(k) Plan

SCE's total compensation plan includes a 401(k) savings plan. In 1999 SCE implemented a change where it now matches 75% of employee contributions up to 6% of base pay. Prior to that change, SCE matched 50% of employee contributions. Employees can defer up to 19% of base pay.

SCE forecasts a test year expense of $32.620 million for the 401(k) program. ORA contends that SCE underestimated an anticipated drop in participation and total payroll, and that SCE has not shown that there will be an increase in the company's match ratio. ORA concludes that SCE has not justified adjusting the company's match ratio by the labor escalation factor. ORA arrived at a forecast of $30.615 million by using the recorded expense for 2001 and by not adjusting the company match ratio. This represents a reduction of $2.005 million.

***Discussion***

We find significant problems with SCE's forecasting methodology. As described in SCE's direct testimony (Exhibit 53, p. 10), SCE used the following methodology to forecast test year 401(k) expenses of $32.620 million:

> Costs were forecast by dividing the recorded 2000 401(k) costs by the 2000 total labor dollars. The resulting ratio was then escalated by the normal labor escalation factor for each subsequent year. The escalated ratio for each year was applied to the forecast labor dollars for the respective years to forecast the expected 401(k) costs.

This issue represents another area, where, despite having presented its most comprehensive showing ever, SCE has failed to provide an adequate explanation for a major expense request (more than $32 million). SCE appears to recognize that the foregoing three-sentence explanation is inadequate, because it provides considerably more explanation in its rebuttal testimony. (Exhibit 302, pp. 142-145.) Unfortunately, this testimony conflicts with the company's direct testimony. In the testimony quoted above, SCE indicated that its forecast was based on 2000 recorded data, labor escalation factors for subsequent years, and forecast labor dollars for 2003. In rebuttal, however, SCE stated that earlier data was also used: "SCE has used [1996 through 2000 recorded adjusted FERC Form 1 data] to develop projections of 2003 expected costs." (Exhibit 302, p. 142.) Thus, where SCE initially stated it used only 2000 and later data, it now states it also used 1996 through 1999 data. Still, it remains unclear how SCE may have used the earlier data.

SCE's rebuttal adds to the confusion in another way. Contending that ORA failed to adjust for changes in employee population over time, SCE notes that the employee population decreased between 1999 and 2001. SCE presents the following data (Exhibit 302, p. 143, Table VII-3):

**SCE Regular and Part-Time Employees (Full-Time Equivalents)**

| 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|
| 13,225 | 13,256 | 12,850 | 11,871 | 12,336 |

SCE contends that the drop in employee population in 2001 makes that year's recorded costs inappropriate for forecasting purposes. The Commission affirmed this view in D.02-04-055, and we agree that ORA's approach may be flawed to the extent that it relies on 2001 data. Nevertheless, we are at a loss to understand why SCE presented population data for 1998 and 1999, which it did not use according to Exhibit 53; or, if Exhibit 302 is more accurate and SCE somehow used 1996-2000 population data in its calculations, why it did not present 1996 and 1997 population data as well. We are also left to wonder what 2003 employee population assumption underlies SCE's forecast.

SCE also admittedly failed to include relevant information in its direct testimony (Exhibit 53). In its reply brief (Footnote 500, p. 118), SCE acknowledges that the ratio between 2000 recorded 401(k) costs and labor expense is not in the record, but suggests that the information may be found elsewhere in the record, since recorded 401(k) costs are included in Exhibits 53 and 302 and total labor costs are shown in Exhibit 59, p. 57. While this late-supplied roadmap information is somewhat helpful, it is nevertheless incumbent upon SCE to show initially, and clearly, the basis for its requests. SCE should not, in effect, invite parties and the Commission on a scavenger hunt through thousands of pages of testimony to find the basis for its requests.

SCE's forecast of $32.620 million represents an increase of 6.9% above the recorded/adjusted 2000 expense of $30.515 million, which increase SCE has not adequately supported. We also conclude that ORA has not provided adequate evidentiary support for its forecast of 401(k) costs. Further, neither SCE nor ORA has proven the predictive value of the cost driving factors they have assumed.[50] Finally, SCE has not overcome ORA's concern that the use of labor escalation factors in SCE's methodology to adjust historical contributions ratios is inappropriate. We will therefore use the last recorded year and adopt a forecast of $30.515 million for SCE's 401(k) program costs. We note that major plan

[50] To the extent that employee population is a principal 401(k) cost driver, the test year forecast would be less than the year 2000 recorded cost because employee population declined from 12,850 in 2000 to "just over" 12,000 in 2003 (Exhibit 55, p. 67.)

changes that could affect program costs, particularly the increase in company matching from 50% to 75%, were in place by that year.

#### 6.7.2.4.3. Health Care Programs

SCE provides health care benefits to it employees and enrolled family members. In addition to providing medical care plans, SCE offers a preventative health account, behavioral health benefits, and employee assistance plan. SCE forecasts test year expenses of $64.411 million for the costs of these benefits. This is an increase of $19.806 million, or 44.4%, above year 2000 recorded costs of $44.605 million. Among the factors impacting the cost of medical care are rising prescription drug costs, increased demand for services, expanding technology and clinical procedures, pressures in the health plan industry, financial deterioration in the health care delivery system, and increased costs due to legislation.

ORA accepts most of SCE's forecast for employee health care programs, and takes issue only with a single component of SCE's medical programs – its corporate fitness center. ORA contends that fitness facilities costs are "employee social, cultural, and charitable activities" that the Commission has historically excluded from rates. ORA proposes a $554,000 reduction to SCE's estimate.

***Discussion***

Contrary to ORA's contention, the fitness center is not a "social, cultural, or charitable" cost. However, we concur with ORA that the issue is whether the fitness center provides clear ratepayer benefits. As we discussed in connection with SCE's requested recognition of the capital costs of the fitness center, the evidence does not allow us to conclude that it provides clear ratepayer benefits, and we therefore adopt ORA's proposed reduction of $554,000. In all other respects, SCE's forecast of health care costs is adopted.

#### 6.7.2.4.4. Miscellaneous Benefits

SCE provides several miscellaneous benefits as part of its total compensation package, including a discount on electric rates, a humanitarian award program, the ACE program addressed earlier, a relocation program, commuter programs, educational reimbursement, and a redeployment program. SCE forecasts total costs of $7.765 million for miscellaneous benefits. Contending that redeployment program costs are restructuring costs that are not handled in GRCs, ORA recommends a reduction of $1.667 million.

***Discussion***

SCE's redeployment program is for employees who become surplus due to business necessity (e.g. organization re-design, re-engineering, or job elimination). The program enables SCE to retain employees with the skills and talent necessary to fill vacant positions, and it assists employees in seeking other career opportunities within the company. SCE agrees that employee redeployment costs related to electric industry restructuring should not be included in this GRC. Moreover, SCE has demonstrated that it removed such costs from its GRC request, and that the $1.667 million in redeployment program costs included in this GRC represent expenses associated with staffing reductions required due to changes in business requirements. Therefore, ORA's proposed reduction will not be approved.

#### 6.7.2.4.5. PBOP Refund Proposal

SCE offers post-retirement benefits other than pensions (PBOP) including medical, dental, vision, Medicare Part B premium reimbursement, employee assistance plan, and term life insurance. SCE forecasts test year PBOP costs of $118.337 million, of which $153,000 is for actuarial fees. The remainder, $118.184 million, is for tax-deductible contributions to independent trusts dedicated solely to PBOP and, for certain employees who retired before January 1, 1993 (the adoption date of Financial Accounting Standard 106) and their spouses and dependents, tax-deductible "pay-as-you-go" costs.

ORA does not take issue with SCE's test year forecast of PBOP costs. However, ORA recommends that SCE be required to make a one-time ratepayer refund of $100.633 million for alleged over-collections of PBOP costs from 1995 to 2000.[51] In its prepared testimony and in the Joint Comparison Exhibit, ORA recommended a refund of $117.915 million. In its opening brief, ORA removed $17.282 million from its refund proposal, thereby acknowledging that SCE made a contribution of that amount in 2000 for the year 1999.

***Discussion***

The following table sets forth the elements of ORA's proposed refund:

**PBOP Over-Collections by Year***
**(Dollars in Millions)**

| | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | Totals |
|---|---|---|---|---|---|---|---|
| Authorized | 97.108 | 97.108 | 97.108 | 97.108 | 97.108 | 97.108 | 582.648 |
| Contributions | 90.784 | 91.591 | 91.146 | 103.369 | 87.843 | 17.282 | 482.015 |
| Over-collection | 6.324 | 5.517 | 5.962 | (6.261) | 9.265 | 79.826 | 100.633 |

* Source: Exhibit 114, p. 14-G-5, Table 14-G-3, revised to reflect ORA's acknowledgment of SCE's $17.282 million trust contribution in 2000.

The data in the foregoing table in the row for "Authorized" represent the amounts that SCE was authorized to recover in rates during the period. These amounts are undisputed. The data in the row for "Contributions," which SCE

[51] ORA indicated at one point that its proposed refund relates to over-collections from 1994 through 2001. (Exhibit 114, p. 14-G-3.) However, the explanatory text and accompanying table (Table 14-G-3) make clear that the review period is 1995 through 2000. (*Id.*, pp. 14-G-4 and 14-G-5.)

contends are incomplete, represent “actuarial certifications” furnished by SCE to ORA in a data request response. Asked about the source of the data in the contributions row, ORA’s witness testified as follows:

> A It's the actuarial certifications, and it's typically known as the development of the market value of assets. And so I would take the 2001 actuarial certification, and I would use the development of the market value assets that contains all the information that occurred during the prior year. And one of the items is Item B, Additions, which one -- which B-1 is contributions, and that's what I used.
> (Tr. V. 28, p. 2466.)

This explanation provides inadequate justification for ORA’s proposed refund of $100 million, and we find no other portion of ORA’s direct testimony that provides the necessary justification. ORA has not demonstrated that the “Contributions” amounts set forth in the foregoing table include all PBOP costs incurred and paid by SCE. SCE, however, has demonstrated that the amounts used by ORA exclude “pay-as-you-go” costs for pre-1993 retirees. Even though these costs are not paid out of a trust, they are nevertheless valid tax-deductible PBOP costs for which ratepayer funding is appropriate and reasonable. Since ORA has not included all appropriate PBOP contributions in the calculation of its proposed refund, we conclude that ORA’s contention that SCE diverted PBOP funds and its related refund recommendation lack merit. The refund therefore will not be approved. Other ORA allegations that arose during cross-examination of ORA’s PBOP witness are not germane and need not be addressed here.

#### 6.7.2.4.6. TURN’s PBOP Proposal

TURN recommended that, consistent with the ratemaking adopted in D.97-11-074, $20,684,000 be treated as a rate base offset because SCE had not contributed to the PBOP trust funds a portion of the accelerated amortization through the Competitive Transition Charge of certain PBOP costs associated with SCE's non-nuclear generation.

***Discussion***

In its rebuttal testimony, SCE stated that the subject contributions were actually made by year-end 2002, including $41.196 million to complete funding of the accelerated transition obligation. Based on this representation, TURN agrees that no rate base offset is necessary, and we will not adopt such an offset.

TURN believes that SCE should be required to submit a late-filed exhibit to confirm that these contributions were included for ratemaking purposes in the test year revenue requirement calculations, i.e., that the generation-related contributions are considered part of the opening balance for determining the return on plan funds. We will not require SCE to submit a late-filed exhibit, but SCE should include this confirmation with the implementation advice letter filing made pursuant to this order.

## 6.8. Public Affairs and Corporate Communications

### 6.8.1. Public Affairs

SCE's Public Affairs Department (PA) represents SCE, its operational departments, and its ratepayers before federal, state, regional, and local governments. PA has 113 full-time employees, not including the Washington office, which is now a part of Edison International. SCE, which serves more than 190 communities (179 cities and 14 counties), states that the vast majority of its PA activity is focused on supporting SCE at the local government level.

Using recorded expenses for 2000, SCE initially forecast test year expenses of $9.489 million for PA in FERC Accounts 920 and 921, consisting of $7.535 million for labor and $1.954 million for non-labor. We now understand

SCE's request to be $7.535 million for labor and $1.926 million for non-labor, for a revised total test year request of $9.461 million.[52] SCE claims that this request excludes costs for activities that do not benefit ratepayers.

SCE states that some of the work performed by specific PA employees constitutes lobbying. SCE seeks a change in Commission policy that provides for the disallowance of lobbying expenses for ratemaking purposes. SCE sees "a principled distinction between the kind of lobbying that seeks ratepayer or both ratepayer/shareholder benefits and that which seeks only corporate or shareholder benefits…." (Exhibit 55, p. 5.) SCE notes that a significant portion of PA time and resources is devoted to responding to proposed ordinances and legislation that would have an adverse cost impact on ratepayers, such as cost shifting among customer classes. SCE also notes that the Internal Revenue Code generally prohibits tax deductibility of lobbying expenses but allows an exception for lobbying of local councils or similar governing bodies. Finally, SCE notes that the National Association of Regulatory Utility Commissioners (NARUC), in audits of the Edison Electric Institute, has observed a distinction between legislative advocacy and legislative policy research. SCE asserts that

[52] SCE's initial forecast appears in Exhibit 55 at p. 9, in a duplicate table at p. 57, and in SCE's rebuttal testimony (Exhibit 302) at p. 241. In the Joint Comparison Exhibit, SCE's PA request is shown as $3.767 million non-labor expense in Account 920 and $950,000 non-labor expense in Account 921, or a total of $4.717 million. (Exhibit 403, pp. 375-377.) The comparison exhibit also shows SCE's PA request as $7.535 million labor expense in Account 920 and $1.926 million non-labor expense in Account 921. (Exhibit 403, pp. 613-615.) The first statement of SCE's position in the Joint Comparison Exhibit appears to reflect the company's difference with ORA and not its own position, as well as an apparently mistaken reference to non-labor expense in Account 920. The second portrayal of its position appears to reflect its initial position as revised to reduce its non-labor expense request by $27,000 (Exhibit 302, p. 248). We therefore assume the latter statement correctly portrays SCE's revised request, and disregard the former.

most of the bill monitoring activities amount to policy research, not advocacy, and that policy research clearly benefits ratepayers.

ORA analyzed the PA function and determined that the major job responsibility of 62 Corporate Representatives/Regional managers is to represent SCE, not its ratepayers, and to engage in lobbying activities on the company's behalf. ORA acknowledges that these employees perform some functions that benefit ratepayers, but not at the rate that SCE's 82.86% allocation factor indicates. ORA recommends that 50% of SCE's labor cost be disallowed, or $3.768 million of SCE's request of $7.535 million. ORA initially recommended that SCE's entire request for non-labor expenses in Account 921 be disallowed based on its contention that SCE had not provided adequate documentation to substantiate its forecast. On the basis of additional discovery, ORA now recommends that 50% of non-labor expenses, or $977,000 of SCE's proposed expense of $1.954 million for non-labor, be disallowed. Finally, ORA recommends that SCE's proposed policy change for lobbying expenses be denied. Aglet supports ORA's positions regarding PA expenses in Account 920 and Account 921.

***Discussion***

There appears to be no issue regarding the general proposition that some PA activities benefit ratepayers while others do not. SCE does not seek full ratepayer funding of PA costs, and ORA and Aglet do not seek a full disallowance of all PA costs. The issue is how to determine the portion of PA costs that should be borne by ratepayers.

Some PA activities, including those that might be characterized as lobbying, can improve the coordination of the local government/utility interface on development projects, or enforce utility franchise agreement rights. To the extent that such activities result in lower utility costs, ratepayers can clearly benefit. Other activities are, at best, of debatable value to ratepayers. For example, as the following colloquy[53] between ORA's attorney and SCE's PA witness demonstrates, PA was active in efforts leading to the passage of AB 1890:

> Q All right. I'd like to understand a little bit more about your group's assessment of what's to the benefit of ratepayers and what is not, or what is to the advantage of shareholders solely. When -- did Public Affairs have anything to do with lobbying associated with the design and enactment of Assembly Bill 1890?
>
> A We -- we were -- we participated in that bill, yes.
>
> Q And that was a very active participation; was it not?
>
> A That's correct.
>
> Q And didn't that also include a suggested writing of the statute, suggested provisions of the statute?
>
> A Yes.
>
> Q At the time did the company consider 1890 efforts by the Public Affairs Department to be efforts to the benefit of ratepayers?
>
> A Yes, and I think it's important to put it in context. Literally, this was a manifestation of a decision of the State to deregulate; it's not something that the utility suggested or pursued. But we were -- at the time of AB 1890, we were pretty well convinced that some form of legislation was going to occur to bring about the State's desire to deregulate. And at the time Edison and the entire Assembly and Legislature in the State believed it was a good bill. I don't think any of us could have predicted some of the things that happened since then. I don't think any of us could have predicted the criminal activity that's being alleged today that's happened as a result of deregulation. So when you ask about do we think the bill was in the ratepayer interest, I think it's important to look at it in the context of when it occurred.

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[53] Tr. V.21, pp. 1770-1771.

> Q Well, in other words, that's the type of activity that you believe should be funded by ratepayers because it has ratepayer benefits; is that right?
>
> A That's correct. We believe that some portion should be funded by the ratepayer.

We doubt that all parties (or all Commissioners) would agree that such activities have clear ratepayer benefits. Without deciding the merits of SCE's participation in the development of AB 1890, or any similar PA activities that might occur in the test year, we simply note that (1) some PA activities are not appropriately funded by ratepayers and (2) there is no bright line that parties have agreed upon to determine the PA activities that clearly qualify for ratepayer funding. While SCE's in-house employee survey of activities is an attempt to determine the proportion of PA activities that benefits ratepayers and the proportion that does not, we are concerned that the survey is permeated with the sort of subjective judgments evidenced by SCE's witness who believes it is appropriate to charge ratepayers for some portion of the costs of SCE's involvement in AB 1890. Ultimately, SCE's analysis is no less subjective than the positions of ORA and Aglet.

We are not prepared to accept SCE's proposed ratepayer funding level for PA activities in this GRC. On the other hand, we find that the ORA / Aglet approach, which would disallow 50% of the PA costs requested by SCE, gives too little weight to the evidence of potential ratepayer benefit of PA activities. For example, SCE estimated that approximately 95% of the Region Managers' time is spent dealing with system operations, customer education, or customer and media responses. These responsibilities include obtaining construction permits, emergency planning, response, and recovery, land-use, issues, and assisting local governments with processing undergrounding requests pursuant to SCE's tariff

Rule 20. SCE has demonstrated that what passes for “influence” at the local level is often conflict resolution that must occur when a local government seeks to impose on SCE costs that ratepayers would have to bear if SCE did not attempt to persuade the local governments otherwise.

In our judgment, a 25% disallowance of SCE’s PA request strikes a fair balance of ratepayer and company interests and gives appropriate weight to the fact that a considerable portion of PA activities are at the local level and have significant potential ratepayer benefit. Accordingly, we will adopt labor related expenses of $5.651 million and non-labor expenses of $1.445 million, or a total PA expense forecast of $7.096 million. This represents a disallowance of $2.365 million.

#### 6.8.2. Franchise Fees

The PA Department negotiates and manages franchise agreements that SCE maintains with each of the local jurisdictions in which it conducts operations. SCE’s forecast of expenses in FERC Account 927 is the product of the estimated sales revenues times the estimated franchise fee factor. SCE’s test year estimate of the franchise fee factor is 0.8470%. ORA initially took issue with this request because it reflected, among other things, an expected renegotiated franchise agreement with the County of Santa Barbara. ORA was concerned that franchise agreement renegotiations with the county had not been completed at the time SCE presented its testimony.

***Discussion***

The Santa Barbara County Board of Supervisors unanimously approved a renegotiated franchise agreement on January 21, 2003. Since the only contested issue regarding SCE’s estimated franchise fee factor has been resolved, we adopt as reasonable SCE’s proposed rate of 0.8470%.

### 6.8.3. Corporate Communications

SCE states that its Corporate Communications department serves as the official voice of SCE to its customers, employees, the news media, and the general public. SCE forecasts a total of $5.503 million for SCE's activities in the test year, consisting of $3.891 million in FERC Accounts 920/921, $1.452 million in Account 930, and $160,000 in Account 923. ORA accepts SCE's forecasts for Accounts 920, 921, and 923, but takes issue with one aspect of SCE's request for Account 930.

SCE's request for Account 930 includes costs for customer bill inserts; customer information brochures, booklets, and website content; and the Edison International (EIX) annual report. ORA proposes a $573,000 reduction for the costs of the EIX annual report. ORA contends that since SCE is required to publish its own annual report at ratepayer expense, shareholders should fund the cost of the EIX annual report.

***Discussion***

Since EIX owns all of SCE's common stock, the shareholders of EIX are also the shareholders of SCE. SCE must communicate with its common equity investors, whose ownership is accomplished through ownership of EIX common stock. A primary information source for those investors is the EIX annual report. The SCE annual report is distributed only to the shareholders of SCE's preferred stock. Finally, we note that EIX shareholders fund a portion of the costs of the annual report ($191,000 in 2000). SCE has shown that ratepayer funding of the annual report of $573,000 is reasonable. ORA's proposed disallowance will not be approved.

### 6.9. Energy Supply and Management (ES&M)

Formed in 1996, ES&M's responsibilities include power procurement, power sales, scheduling and dispatching generation, interutility power contract administration, coal contract administration, generation-related regulatory reporting functions, forecasting related to load and T&D system usage, and energy planning (e.g., price forecasting, power procurement planning, and procurement risk management). When the restructured electricity market was implemented in April 1998, ES&M assumed primary responsibility for the interface between SCE and both the ISO and the PX. When the PX ceased operations in January 2001, ES&M became the Scheduling Coordinator for SCE's retail customers and its generation.

Using a budget-based approach, SCE forecasts total test year expenses for ES&M of $16.590 million in FERC Accounts 920, 921, and 501. This is an increase of $7.311 million, or 79%, over the 2000 recorded expense of $9.279 million. SCE indicates that this increase is largely explained by the department's assumption of energy procurement responsibilities that, prior to 2003, were performed by the California Department of Water Resources (DWR) pursuant to ABX1-1 and an April 9, 2001 Memorandum of Understanding between DWR and SCE. Among other things, the DWR contracts might obligate SCE to be responsible for procuring between 63 and 165 billion cubic feet of gas per year. SCE estimated that ES&M needed to increase its staff full time equivalents (FTEs) by 31, from 82 in 2001 to 113, in 2003, including an increase of 9 FTEs for power contracts (from 6 to 15) and 8 FTEs for gas procurement (from zero to 8).

SCE's GRC request of $16.590 million was based on information available in mid-2001. SCE noted in supplemental testimony (Exhibit 69) submitted pursuant to the Assigned Commissioner's scoping memo that it expects ES&M costs to significantly exceed the company's GRC forecast.

ORA recommends that a forecast of $14.258 million be adopted for ES&M, or $2.332 less than SCE's forecast. ORA agrees that SCE's assumption that it would assume DWR procurement functions was reasonable. ORA also agrees that it is reasonable to use a budget-based approach to forecast ES&M expenses. Nevertheless, ORA concludes that SCE's staffing levels are somewhat high based on comparisons with similarly situated utilities. ORA contends that SCE did not provide sufficient specific information justifying the increase in Gas Procurement staff and certain other staff increases, or increases in overhead associated with IT application and system special services.

***Discussion***

An increased funding requirement of 79% for a department is potentially alarming, but we recognize that the ES&M function is deeply impacted by the events in the electricity market of the past three years and the State's efforts to deal with the aftermath of those events. For this reason, we agree with both SCE and ORA that recorded data from 1996-2000 are of little value in forecasting test year ES&M expenses, and that a budget-based approach is appropriate. Unfortunately, because of the uncertainty associated with the new and evolving ES&M functions, it appears that both SCE and ORA were forced into a position of having had to arrive at their respective forecasts with an element of "shooting in the dark."

This dispute largely turns on judgments regarding the staffing levels required to fulfill the ES&M responsibilities in 2003. Based on an analysis of the number of fuel and power supply contracts managed by ES&M and the number of staff, ORA does not believe the increase of 31 FTEs in 2003 is justified. For existing divisions, ORA recommends that funding for eight of the 23 FTEs proposed by SCE be denied. ORA also recommends that funding for four of the eight FTEs in the new Gas Procurement division be denied.

We find neither ORA's comparative utility analysis nor its contract-staff ratio analysis to be persuasive support for ORA's judgment of the number of ES&M staff required. The former is not demonstrated to be a valid "apples to apples" comparison across utilities, and the latter relies on assumptions about the simplicity and uniformity of contracts that we are unwilling to make. Also, not all ES&M work is contract related. Further, it is possible that ORA may have underestimated the likely number of contracts that ES&M would negotiate in 2003. SCE has also shown that it will incur additional expenses for procurement risk management that were not included in its forecast. Finally, ORA has not substantiated the assumptions underlying its estimate of the number of staff needed for gas procurement.

ORA acknowledges that SCE personnel are in the best position to determine the staffing requirements of ES&M. We will accept SCE's judgment of those staffing requirements as the most reliable predictor of ES&M costs for the test year. Accordingly, SCE's test year forecast for ES&M expenses is adopted.

### 6.10. Reimbursable Expenses Error Rate

Pursuant to GO 77K, SCE reports on the compensation of employees whose compensation exceeds $75,000, including reimbursable expenses. SCE's GO 77K report for 2000 shows that total reimbursable expenses were $11.330 million for approximately 2,600 employees. In connection with this GRC, SCE reviewed reimbursable expenses of employees whose total reimbursable expenses exceeded $25,000 per employee. SCE found that 53 employees had such expenses that totaled to $2.287 million. For these employees, SCE determined that $267,092 of the $2.287 million was for expenses such as fundraising, charitable activities, country club dues, and similar expenses that should be treated "below-the-line," i.e., not funded by ratepayers.[54] SCE therefore removed at least $226,253 of the $267,092 from its GRC request.

Based on the relationship between the $267,092 in below-the-line expenses and total expenses of $2.287 million for these 53 employees, ORA calculated an "error rate" of 11.69%.[55] ORA determined that this error rate should be applied to the reimbursable expenses of $9.043 million for the remaining employees whose reporting was not reviewed by SCE. ORA thereby arrived at a recommended disallowance of $1.057 million.

Upon reviewing ORA's testimony, SCE analyzed the error rate for the $9.043 million in expenses that it did not review in its direct testimony. SCE developed a sample of 246 employees with total expense reimbursements of $210,357. SCE determined that $209,395 or 99.54% of this amount was correctly charged to ratepayers, and that $962, or 0.46%, was erroneously charged to ratepayers. SCE agrees that $962 should be removed from the GRC request in addition to the $226,253 or $267,092 that it previously removed.

***Discussion***

SCE's direct testimony in this proceeding relied on the unreasonable proposition that even though 53 employees were known to have erroneously

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[54] SCE reduced this adjustment by approximately $41,000 then, upon reviewing ORA's testimony, agreed to reinstate the $41,000 reduction. However, SCE admits that it has not been able to identify adjustments for $40,839. (Exhibit 307, p. 15, Footnote 28.)

[55] We note that $267,092 is 11.68% of $2,286,998.

charged non-qualifying expenses to ratepayers at a rate of 11.68% of reimbursable expenses, it was nevertheless reasonable to assume that approximately 2,547 employees (2,600 employees whose compensation is reported under GO 77K less 53 employees whose reporting errors SCE actually studied) reported their reimbursable expenses with a zero error rate. However, SCE's direct showing failed to include support for a zero error rate.

It was only when ORA highlighted the unreasonableness of SCE's position that SCE studied the issue. SCE's presentation of its statistical analysis is improper and unfair rebuttal and is therefore disregarded.[56] Moreover, even if we were to adopt SCE's study and accept its conclusion that the error rate is 0.46%, SCE only agreed to forego the $962 in incorrectly charged expense reimbursements associated with the sample. Thus, even in its rebuttal, SCE continues to assume that error rates it chooses not to study must be zero. At a minimum, even under its own study conclusions, SCE should have applied the 0.46% error rate to the population of $9.043 million.[57]

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[56] Were we to consider this testimony, we would be concerned with SCE's methodology. SCE's sample is 246 employees with total expenses of $210,357, or an average of $855 per employee. This is drawn from a population of approximately 2,547 employees with total expenses of $9.043 million, or an average of approximately $3,550 per employee. We believe that the discrepancy between $855 in the sample and $3,550 in the population calls into question the validity of SCE's methodology.

[57] In describing its study methodology, SCE may have disclosed a further weakness in its analysis. SCE states that "[t]he $9,042,852 population was not stratified because there was no reasonable basis to conclude that one group of reimbursable expenses had a greater likelihood of including shareholder expenses." (Exhibit 307, p. 19.) Actually, SCE itself stratified the total population by choosing to separately analyze expenses over $25,000. If anything, SCE's belief that there is no reasonable basis for concluding that one group of reimbursable expenses has a greater likelihood of including shareholder expenses would support ORA's position.

SCE's proposal for a zero reporting error rate for employees with expenses under $25,000 lacks evidentiary support, and its agreement to forego collection of $962 in rates is inadequate. We will therefore adopt ORA's recommended correction and reduce SCE's authorized expenses of $9.043 million by an error rate of 11.68%, or $1.056 million. We also reduce authorized expenses by $40,839 for incorrectly charged expenses of 53 employees that SCE agrees should be excluded in addition to the $226,253 in adjustments it was able to document.

SCE's unwillingness to make corrections even after being confronted with evidence of their necessity is troubling. We will require that for its next GRC, SCE conduct a study, using appropriate statistical methodology, of reporting errors for reimbursable expenses of all employees, including those not subject to GO 77K reporting requirements.

## 7. Other Audit Issues – Affiliates

### 7.1. Introduction

ORA reviewed and analyzed SCE's affiliate/subsidiary transactions to determine SCE's compliance with Commission rules governing affiliate transactions and relationships and to determine the reasonableness and ratemaking implications of inter-company transactions insofar as they affect ratepayers.

### 7.2. Edison Select Costs

Edison Select was a subsidiary of Edison Enterprises providing consumer products and services for the retail mass market. It was sold in August 2001 and is no longer an affiliate of SCE. SCE continues to provide billing services to the purchaser, ADT.

ORA proposes that all accounts relating to Edison Select be excluded from this GRC. Specifically, ORA recommends that expenses reported in FERC

Accounts 901 and 903, Functions 5344 and 5347, as well as credits and reimbursements in Accounts 901 and 903, Functions 5333 and 5334, be excluded. As shown in the Joint Comparison Exhibit (Exhibit 403, p. 281), ORA's proposal results in a reduction in Account 901 of $313,000.

***Discussion***

SCE's contention that all costs associated with providing non-tariffed products and services are fully recoverable from ratepayers does not square with D.99-09-070, which adopted a gross revenue sharing mechanism. ORA's proposal to exclude those costs is consistent with D.99-09-070 and will be approved.

### 7.3. Energy Marketing Affiliate

Under Affiliate Transaction Rule V.G.2.e, established in D.97-12-088 and modified in D.98-08-035, utilities are prevented from making temporary or intermittent assignments or rotations to energy marketing affiliates. In its Report on Results of Examination, ORA states that it considers Edison Mission Energy (EME) to be an energy marketing affiliate. ORA believes that under the Commission's affiliate transaction rules, temporary assignments of SCE personnel should no longer be allowed. SCE opposes this recommendation. SCE contends that while EME has subsidiaries that market energy, EME itself and most of its subsidiaries do not do so.

***Discussion***

There are no ratemaking implications for this GRC associated with ORA's recommendation. Moreover, accepting ORA's recommendation would require accepting its definition of "energy marketing affiliate," which could potentially implicate the interests of other utilities that did not participate in this GRC. Therefore, without addressing the substantive merits of ORA's recommendation, we decline to act on it at this time. We note that pursuant to Affiliate Transaction Rule V.H., SCE is reimbursed by affiliates, including EME, for all temporary assignments completed by SCE employees.

## 8. Rate Base

### 8.1. Plant Balance Weighting Percentage

When a capital project is completed, it is added to the plant-in-service balance and begins earning a return. Because plant additions occur throughout the year, the timing of project completions must be taken into consideration so that returns will not be earned before projects are completed. This is addressed by "weighting" projects according to their estimated completion dates. A project completed early in the year is weighted at close to 100%, whereas a project completed late in the year would be weighted at closer to 0%.

SCE recommends that the weighting of total plant balances be consistent with the individual project completion dates in its capital budget. In support of this approach, SCE points out that all of its business units undertake a rigorous capital budgeting process, and that each budget item includes the type of project, material required, labor estimates, total cost of the project estimates, the beginning and ending dates of construction, and other detailed information regarding the project. SCE further notes that each business unit has an intimate knowledge of its capital budgeting needs, including especially when expenditures need to be made and when projects will be placed in service.

ORA believes that the 50.55% weighting percentage associated with SCE's budget-based approach is too high. ORA determined that the historical average weighting percentage for the nine-year period 1993-2001 was 42.51%, and used this percentage to calculate the 2003 weighted average plant balances. As shown in Exhibit 403 (at p. 471), the difference in SCE's and ORA's approach results in a difference in plant of $64.446 million.

***Discussion***

SCE raises a variety of minor concerns with ORA's analysis that represent distractions not warranting discussion. This issue turns on the larger question of whether the individual project forecasts developed by SCE's various business units (SCE's approach) yield a more reliable overall plant forecast than one based on SCE's actual experience with project completion (ORA's approach).

Notwithstanding SCE's claims that its method is more rigorous and sophisticated, and is based on the intimate knowledge of business unit managers, SCE has not demonstrated that rigor, sophistication, and intimacy yield more accurate and reliable forecasts than the historical record. SCE improperly attempts to shift the burden of proof to ORA in this GRC by pointing out that ORA provided no conclusive explanation of why an average of historical weighting percentages better represents the plant weighting than a detailed budget. The more pertinent question, not adequately addressed by SCE, is why its budget-based approach, which suffers from the problem that budgets are not always carried out as planned, is necessarily more accurate and reliable than data based on actual performance over an extended period.

The average (mean) weighting percentage over the past nine years was 42.51%, and the reliability of this value as a predictor is reinforced by the median value of 43.54%. The range of weighting factors was 33% to 51%. What is it about the year 2003 that leads to the estimated completion of projects unusually early in the year, at a pace that results in a weighting percentage roughly equal to the highest value of the last nine years? Apart from its insistence that its business unit managers just know better, which proposition we are unwilling to accept absent corroborating information, SCE does not provide us with an answer to this question. Therefore, ORA's proposal to use the mean value is the most reasonable approach supported by this record, and it will therefore be adopted. We will approve a correction agreed to by ORA, and adopt a weighting factor of 42.554% in lieu of 42.51%.

### 8.2. Materials and Supplies Inventory

The utility's Materials and Supplies (M&S) inventory is a component of working capital, which in turn is a component of rate base. SCE's Procurement and Materials Management Department (PAMM) forecast M&S by various business units for the years 2001 to 2003. PAMM could not provide estimates of Supply Expenses and Unpaid Invoices, so SCE used the year 2000 relationships between recorded M&S and these functions to develop forecasts for Supply Expenses and Unpaid Invoices. Using this approach, SCE arrived at a total weighted average M&S forecast of $66.693 million for 2003.

ORA has concerns about (1) SCE's use of only one recorded year to develop the M&S ratios, (2) whether those ratios are reasonable proxies for future years, and (3) whether SCE's 2002 and 2003 estimates of the various M&S accounts are reasonable. ORA proposes the use of five years of recorded data (1997 to 2001) to forecast M&S. Using this approach, and adding $6.5 million to account for Palo Verde M&S because that facility is returning to cost-of-service ratemaking, ORA arrived at an M&S forecast of $61.345 million for 2001, or $5.348 million less than SCE's forecast.

***Discussion***

As shown in Exhibit 214, the weighted average M&S increased in 2001 by $6 million over the recorded level for 2000, and SCE reported in its rebuttal testimony (Exhibit 305, p. 6 and Appendix A-1) that the weighted average M&S

increased by an additional $2.3 million in 2002. SCE claims that this is evidence of an increasing trend, and shows that its methodology is conservative.

However, an analysis of the recorded M&S figures for the years 1996 through 2002, taken from Exhibits 214 and 305 and shown below, does not necessarily support the conclusion that M&S is undergoing an increasing trend. Asked about data for the years 1996 through 2001 (2002 data was not available when the witness testified), ORA's witness testified that, with the exception of the year 2001, he found a decreasing trend. (Tr. V. 32, p. 2951.)

**Weighted Average M&S – Recorded**
**($Millions, excludes nuclear)**

| 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|---|
| 56.135 | 55.036 | 53.217 | 54.108 | 52.856 | 59.008 | 61.262 |

Even if there is an increasing trend in M&S, as the 2002 data may indicate, SCE has not explained why this would be occurring. We have no basis for concluding that any such increases are a just and reasonable basis for a forecast. We are again left with little more than assertions that detailed analyses have been performed, in this case by PAMM. In the absence of information regarding the cause of any increasing trend, a five-year average is a more reliable basis for forecasting M&S. We will use an average of the years 1998 through 2002, $56.090 million, and add $6.5 million for Palo Verde M&S to arrive at an adopted M&S forecast of $62.590 million.

### 8.3. Working Cash

Working cash is included in rate base to compensate the utility for funds advanced by investors. The Joint Comparison Exhibit (Exhibit 403, p. 590) shows SCE proposing a working cash estimate of $52.705 million and TURN proposing reductions from that estimate totaling $27.926 million. However, a major component of TURN's proposed reduction pertains to Other Accounts Receivable. TURN had proposed a reduction of $21.112 million to remove non-recurring balances from steam power plant O&M in 2000. SCE submitted errata testimony in which it used escalated, recorded data for 2001 to forecast the balance in this account, essentially resolving TURN's concerns with this account. TURN now accepts SCE's revised forecast for the Other Accounts Receivable component of operational cash. Thus, the Joint Comparison Exhibit does not appear to be representative of the parties' positions.

While the briefs and the Joint Comparison Exhibit are not clear on this point, it appears that the remaining differences between SCE and TURN with respect to working cash relate to TURN's recommended reductions regarding employee withholding and accrued vacation ($5.166 million), arithmetic corrections ($1.039 million), and the lead-lag study ($6.157 million).

***Discussion***

TURN's testimony regarding the need for adjustments for Employee Withholding and Accrued Vacation ($5.166 million) and arithmetic corrections ($1.039 million) is unrebutted, and SCE did not address these issues on brief. We take SCE's silence on these proposals to be a concession that TURN's analysis is correct. Similarly, SCE has not responded to TURN's recommendation to increase the labor lag in the lead-lag study by 1.22 days, resulting in an adjustment of $2.227 million. TURN has demonstrated that these uncontested adjustments are reasonable, and they will therefore be adopted.

TURN's other working cash adjustments pertain to SCE's inclusion of insurance provisions in the lead-lag study. TURN proposes to remove property insurance provisions from the lead-lag analysis both because of duplication with prepayments and a high cost estimate. TURN proposes to remove liability insurance because of duplication with prepayments. TURN's proposed adjustments total to $3.930 million, consisting of $3.322 million for property insurance and $0.608 million for liability insurance.

SCE has demonstrated that TURN's concern about double counting of insurance provisions is unfounded. Even though insurance provisions represent prepayments, they are properly included in the lead-lag study to compensate the utility for the use of capital. The prepayment amount that TURN contends is double-counted is actually a balance sheet entry related to SCE's cash requirements. Because SCE makes these payments up front with cash, they are also properly included in the working cash calculation. SCE's approach is also consistent with the Commission's Standard Practice U-16. With respect to the contested amount of property insurance, SCE has shown that in addition to FERC Account 924, there are several other accounts that must be totaled to arrive at the correct amount to use for the lead-lag study. Accordingly, TURN's proposed adjustments for insurance provisions are not warranted, and will not be adopted.

As discussed by ORA in Exhibit 114 (p. 18-6), SCE reduced its revenue lag for domestic customers by one day in anticipation of the adoption of its proposed late payment charge (LPC). Because ORA opposed the LPC, it added back the one day that SCE removed from the revenue lag. Since we are adopting SCE's proposed LPC (Section 5.3.2), we will adopt SCE's reduced revenue lag of 37.07 days for domestic customers.

### 8.4. Customer Advances for Construction

Customer Advances for Construction (customer advances), i.e., funds paid by applicants (developers) for plant, are an offset to rate base. Using a five-year average, SCE forecast an offset of $35.693 million for customer advances, while TURN forecast an offset of $49.753 million, a difference of $14.060 million. TURN believes that SCE improperly failed to consider that line extension rules effective July 1, 1998, pursuant to D.97-12-098, have reduced free allowances and therefore increased customer advances. In addition, TURN notes, recorded customer advances were $6 million higher than SCE's forecast by the end of 2001 and $14.4 million above SCE's forecast for 2002. TURN finds an increasing trend for this account, and bases its forecast on the most recent recorded data. The following table, showing recorded data taken from Exhibit 231, p. 29, illustrates TURN's contention.

**Customer Advances for Construction**
**Recorded End-of-Year* ($Millions)**

| 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|---|
| 35.482 | 31.619 | 33.960 | 37.079 | 38.604 | 41.270 | 49.753 |

*Year 2002 data is as of October

During the rebuttal hearings, SCE updated its forecast using recently available recorded data and the five-year averaging methodology it used for its initial estimate. SCE now forecasts customer advances of $45.503 million, or $4.250 million less than TURN's forecast.

***Discussion***

If, as TURN contends, there is an increasing trend for this account, then a five-year average of data could give inappropriate weight to earlier data that is no longer representative of current conditions. TURN bases its contention of an increasing trend on the 1998 change in line extension rules, but the evidence presented by SCE shows that this does not necessarily explain the recent increase in this account. In fact, customer advances per meter have gone down. Moreover, SCE's revised estimate uses data from 1998 to 2002, which would incorporate the effect of the 1998 change in customer advances. Customer advances are also affected by general economic trends, including the level of interest rates, development schedules and higher density construction. These factors are incorporated into a five-year average, but not in a single year's recorded balance.

The record does not allow us to draw a firm conclusion on the question of whether there is a continuing increasing trend in customer advances. If such a trend exists, however, it is not linked solely to the 1998 line extension rule change. Instead, it is also attributable, perhaps primarily so, to general economic conditions. Under the circumstances, we find that averaging is more appropriate than a single year's data, and we therefore adopt SCE's revised forecast.

### 8.5. Customer Deposits

SCE requires that an applicant for new service establish credit under Tariff Rule 6. A customer who has not qualified for the establishment of credit with the utility must submit a deposit pursuant to Tariff Rule 7. SCE is required to refund customer deposits with interest within 12 months as long as the customer pays his or her bills timely.

TURN notes that the amount of customer deposits received and held by SCE is substantial. With the exception of the year 2000, SCE has held over $80 million in customer deposits at the end of each year from 1996 to 2001. On a monthly basis, customer deposits have exceeded $60 million since January 1998. Total customer deposits have increased since March of 2002, and as of October 2002, SCE held over $142 million of its customers' money as deposits.

TURN contends that customer deposits represent a permanent source of working capital not provided by investors. However, customer deposits are not counted as an offset to the operational cash requirement under current practice. This is because SCE pays interest on the deposits (at the three-month commercial paper rate, which is currently less than 2%), and the Commission's Standard

Practice U-16 (U-16) indicates that while interest-free customer deposits should be counted as working cash, those on which the utility does pay interest should not be counted as working cash.

TURN therefore recommends that the Commission, as a matter of policy, amend the "interest-free" restriction of U-16 as it specifically relates to customer deposits held by SCE. TURN's specific recommendation in this GRC is to reduce SCE's rate base by $117.174 million, based on the most recent 13-month average of customer deposits (October 2001 to October 2002). TURN believes that this calculation is conservative in light of the large increase in deposits between March and June of 2002, as well as the most recent recorded figure of $142 million. TURN further recommends that if the Commission treats deposits as a rate base offset, it should also increase SCE's operating expenses by $3.343 million to reflect interest payable on customer deposits at a projected interest rate of 2%.

SCE opposes TURN's recommendation on the grounds that it is inconsistent with U-16. Noting that customers generally pay their bills on time, and that half of SCE's customer deposits are refunded each year, SCE also claims that deposits are not a permanent source of capital. Additionally, SCE claims that TURN's recommendation is inconsistent with the Commission's treatment of fuel inventory working capital.

***Discussion***

TURN raises numerous factually based arguments in favor of its proposal as summarized below. We find each of them to be meritorious, and that in combination they represent a convincing case for revising SCE's practice as proposed by TURN.

- Customer deposits are a substantial, permanent source of working cash provided by ratepayers, unlike short-term debt borrowed to fund balancing account undercollections or as a bridge before permanent long-term debt or equity financing is obtained. As deposits are repaid to some customers, other customers submit new deposits. Thus, while there is continuous turnover, the average daily and monthly balances stay relatively constant.
- TURN's proposed treatment of customer deposits is analogous to the treatment of employee vacation as a permanent source of capital not provided by investors. The only relevant difference between accrued vacation and customer deposits is that interest is paid on the deposits.
- Even though U-16 does not currently provide for the treatment proposed by TURN, it specifies that the operational cash requirement be reduced by an amount that represents a source of interest-free working funds available to the utility due to the fact that revenues are collected prior to the payment of employees' wages, taxes and the utility's creditors, and it identifies several liabilities accounts that should be considered as deductions, including customers deposits.
- Circumstances have changed since U-16 was developed over 30 years ago. TURN does not generally take issue with the underlying policy for the U-16 limitation that only interest-free working funds will be deducted from the operational cash requirement. In fact, TURN submits that excluding certain liability balances that pay interest, such as balancing account undercollections, is clearly reasonable. However, even if at the time U-16 was adopted it was reasonable to assume that customer deposit amounts would be relatively small, and interest rates would be relatively large compared to rates of return, that is no longer true.
- It is appropriate to deviate from U-16 for the specific case of SCE's customer deposits, based on the substantial increase in the amounts of these funds and relative decrease in the applicable interest rates. SCE pays less than 2% interest annually on customer deposits, based on present commercial interest rates. At the same time, SCE's rate of

return on rate base (including working capital supplied by investors) is in excess of 13%, including income taxes on the equity return. TURN submits that there is no danger that including customer deposits in working cash would deprive investors of their opportunity for earnings. The interest payable to ratepayers is small and should be included in SCE's operating expenses.

- The Commission has adopted deviations from U-16 in utility-specific rate cases. In D.93-01-025, the Commission noted a need to revise U-16 but did not to do so because not all affected utilities were parties to that proceeding. (47 CPUC 2d 580, 593). Nevertheless, the Commission found that circumstances warranted deviation from U-16 for a specific utility. (*Id.*, 594.) In D.93-12-043, the Commission again noted that U-16 was out of date and adopted a deviation applicable to Southern California Gas Company. (52 CPUC 2d 471, 519.) In D.94-02-042, Finding of Fact 42, the Commission held that the procedures in U-16 "serve only as a guide [and] do not preclude deviations appropriate to special circumstances." (53 CPUC 2d 215, 249-250.)
- Several states reflect customer deposits either as a reduction to rate base (working capital not provided by investors) with interest added back to operating expenses (Arizona, Oklahoma, Maryland) or as an element of the capital structure itself (Arkansas, Nevada). Thus, TURN's proposal will bring California ratemaking practice into conformity with that of other states.

SCE's contention that TURN's proposal is inconsistent with U-16 begs the question. TURN acknowledges that SCE's current practice follows U-16, and understands that a deviation is required. As the Commission has previously held, U-16 is only a guide, and deviations are appropriate where circumstances warrant. TURN has demonstrated that such is the case here, since customer deposit amounts are no longer small, while interest rates are relatively low compared to rates of return.

The record does not support SCE's contention that customer deposits are not a source of permanent capital. Even if, as SCE claims, customer deposit balances fluctuate dramatically over time such that as much as half the customer deposit balance turns over each year, that does not mean they are not permanent capital. The fact that certain portions of the balance turn over each month or year, as some customer deposits are returned and others collected, does not change the fact that SCE has access to a consistent monthly balance of over $60 million. Nor does the fact that short-term interest rates are paid to customers on their deposits change the essential fact that SCE continues to have significant balances month after month. SCE agrees that other sources of working cash such as employee accrued vacation also turn over. Also, SCE's argument ignores the fact that U-16 itself acknowledges that interest-free customer deposits are a source of working cash.

SCE contends that TURN's proposed treatment of customer deposits is inconsistent with the Commission's treatment of fuel inventory working capital. When SCE carried large amounts of fuel oil inventory, it requested that some minimum level of inventory be considered permanent. The Commission rejected this position, and SCE received only short-term interest rate recovery for its fuel oil inventory. However, in rejecting SCE's proposal to rate base a portion of fuel inventory, the Commission held that "the risk Edison is offering to assume [of a change in value of the inventory] is not significant enough to justify a change in financing of the carrying costs." (64 CPUC 2d 241, 382, Finding of Fact 110-111.) SCE has not demonstrated to our satisfaction that the circumstances that led the Commission to reject SCE's proposal to rate base fuel inventory are equivalent to the circumstances attendant to TURN's proposal for customer deposits.

We conclude that TURN's proposal to apply an estimated $117.174 million customer deposit balance as an offset to rate base is reasonable and should be adopted, along with TURN's proposal to increase SCE's operating expenses to reflect interest payable on customer deposits at a projected interest rate of 2%.

However, we will not adopt TURN's proposal to increase expenses by $3.343 million. We will instead adopt increased expenses of $2.343 million, or 2% of $117.174 million.

## 9. Depreciation and Amortization

### 9.1. Introduction

Depreciation is the recovery of the original cost of fixed capital, less estimated net salvage, over the useful life of the property. Consistent with the Commission's Standard Practice U-4, *Determination of Straight-Line Remaining Life Depreciation Accruals*, as well as standard practice throughout the electric utility industry, SCE calculated depreciation expenses using accrual rates based on the straight-line method using the remaining life technique. SCE recommends test year depreciation expenses of $44.287 million for SONGS 2&3, total nuclear plant depreciation expense of $53.749 million, and non-nuclear depreciation expenses of $715.125 million. ORA and TURN recommend substantially lower expenses for both SONGS 2 & 3 and overall depreciation, as shown in the following table:

**Depreciation Expense - Summary of Differences***
**($ Millions)**

| | Proposed Expense | Difference v. SCE |
|---|---|---|
| **SONGS 2 & 3** | | |
| SCE | 44.287 | -- |
| ORA | 21.089 | 23.198 |
| TURN | 21.162 | 23.125 |
| **Excluding Nuclear** | | |
| SCE | 715.125 | -- |
| ORA, depreciation rates only | 636.906 | 78.219 |
| ORA, including plant differences | 605.040 | 110.085 |
| TURN** | 531.349 | 183.930 |

* Source: Exhibit 403, pp. 513-515, and 595-596.

** TURN / SCE difference is based on SCE's initial plant estimate and its depreciation expense estimate of $715.279 million.

The two most significant factors affecting the parties' depreciation expense estimates are net salvage (gross salvage less cost of removal) and service lives, which directly impact remaining lives. SCE contends that in recent years the cost of removal has exceeded gross salvage, which produces negative net salvage and in turn increases depreciation rates. SCE also notes that in recent years average service lives have been increasing, which produces lower depreciation rates.

SCE's total recommended annual depreciation expense for 2003 is an increase of approximately $148 million from the recorded 2000 expense (excluding 2000 accelerated nuclear sunk). This increase is made up of $77 million due to SCE's updated depreciation study (discussed in the following section) and $71 million due to forecast changes in plant between 2000 and 2003. The $77 million requested increase associated with SCE's updated depreciation study consists of a $9 million decrease associated with SCE's life analysis (i.e., longer remaining service lives) and an $86 million increase associated with increased negative net salvage.[58]

### 9.2. Depreciation Study

SCE states that its net salvage determinations were made according to Standard Practice U-4. The net salvage ratios for each account were based on analyses of 15 years of historical gross salvage and cost of removal data for the period ending December 2000. SCE states that the final estimates of the net salvage ratios were moderated by judgment and knowledge of the account.

For its life analysis, SCE performed a review of the average service lives and mortality dispersion characteristics for all plant accounts in all plant categories, also based on methods specified in Standard Practice U-4. These methods include the survivor curve method, the forecast method, and direct judgment. For generation, SCE used the remaining life of coal plants, the NRC license life of Palo Verde plant, the estimated remaining life of the steam generators at SONGS 2 & 3, and the FERC license life of hydro plants. For T&D plant, which consists of a multitude of similar assets grouped by FERC account referred to as mass property, SCE simulated mortality experience and statistically developed an average service life and remaining life for each FERC account using the Iowa State Simulated Plant Records (SPR) program based on simulated plant balances (Bauhan method). SCE used judgment for its estimate for Account 390 – Structures. SCE states that it tempered its determinations of remaining life with

[58] TURN noted that a correction to SCE's life analysis was required, and SCE subsequently adjusted the $77 million increase to $70 million.

technical information about equipment and its operation obtained from company technicians and management, comparative industry statistics, and judgment.

TURN's depreciation witness addressed SCE's estimates of mass property service life, mass property net salvage value, and Four Corners depreciation. TURN determined that, in its opinion, SCE regularly ignored the best fitting statistical results of its mass property life analyses and inappropriately interpreted information from in-house technical operational personnel to arrive at inadequate average service lives. TURN recommends longer service lives and/or different dispersion patterns for 9 of 10 accounts reviewed. With respect to mass property net salvage, TURN believes that SCE (1) generally ignored comparable industry information, since the company's proposals are in many instances much more negative than comparative industry indicators; (2) relied on unsupported or inadequately supported statements of technical/operational personnel; (3) relied on flawed statistical analysis by failing to recognize portions of accumulated provision for depreciation in a manner that would lessen negative net salvage; and (4) improperly used information that allocates costs incurred in replacement activity to cost of removal rather than a component of new installation. TURN recommended adjustments to net salvage for 10 mass property accounts. With respect to Four Corners depreciation, TURN recommends suspension of all recovery of depreciation expense.

While it does not take issue with SCE's study of asset service lives, ORA recommends that the currently authorized depreciation rates, including current parameters for life and salvage, be applied in this GRC. ORA's recommendation is based on its belief that the "skyrocketing" negative net salvage values reflected in SCE's depreciation study require further investigation before SCE's depreciation rates are increased on the basis of negative net salvage. ORA recommends that the Commission order such an investigation. ORA notes that the estimated negative salvage costs associated with SCE's recorded Gross Plant of approximately $14 billion as of December 31, 2000 was approximately $3.4 billion. For 2003, the results of SCE's depreciation study suggest that the funding for negative net salvage would be increased by about 70% to $5.7 billion.

ORA believes that retaining the current service lives for non-nuclear assets is consistent with its recommendation to use the currently authorized net salvage factors. ORA also notes that under SCE's proposal, service lives for most accounts change little if at all. Finally, ORA notes that SCE's study is heavily influenced by engineering judgment, and it contends that the conclusions in SCE's study are subject to varying interpretations that depend on the bias and judgment of the reviewer.

***Discussion***

Both SCE's and TURN's depreciation analyses and recommendations represent the work product of experienced and qualified utility depreciation experts who had access to SCE's technical and operational personnel with knowledge about the engineering and operational characteristic of utility property. We note, however, that both SCE and TURN emphasize the importance of informed judgment on the part of depreciation professionals in arriving at their respective recommendations. ORA has also noted the degree to which judgment underlies SCE's recommendations.

After reviewing the intricate record on depreciation issues, we are left to conclude that the extensive exercise of subjective and potentially biased judgment by the respective depreciation experts renders their analyses and recommendations unreliable for purposes of ordering major changes in depreciation parameters and expenses. We are particularly concerned with the lack of adequate, verifiable substantiation for SCE's calculated increase in negative salvage values for mass property. As just one example, we note that SCE failed to demonstrate that compliance with environmental protection requirements has added substantially to negative net salvage since the last depreciation study. Also, SCE has not adequately demonstrated that its use of contract labor is a significant contributing factor to a multi-billion dollar increase in negative net salvage. We seek greater assurance than SCE was willing and able to provide that any substantial increase of negative net salvage that may be occurring, such as the $86 million annual expense increase that it calculated, is being caused by exogenous factors and not merely by changed approaches to depreciation accounting. We are also concerned with TURN's life analysis, which may rely on unconventional use of accepted analytical tools and techniques such as the Retirement Experience Index, as well as TURN's apparent over-reliance on old comparative industry data. TURN's proposal to base Four Corners salvage on the past experience of fossil unit sales lacks merit. We conclude that neither SCE nor TURN has sustained its respective burden of proving that its depreciation proposal is justified.

SCE points out that the currently authorized depreciation rates were adopted in its last GRC and are the product of a depreciation study conducted approximately 10 years ago. Because the use of inaccurate depreciation rates can result in inter-temporal inequities by requiring current ratepayers to pay too much or too little for the assets used in providing utility service, we would prefer not to use rates that are the product of a 10-year old deprecation study. Unfortunately, for the reasons discussed above, we are left with no acceptable alternative in this GRC to using the currently authorized depreciation rates. We will therefore adopt ORA's recommendation to do so. We address ORA's proposal to deny amortization of easements below.

With the passage of time, it will be even more important in SCE's next GRC to have an updated depreciation study, upon which we can rely with confidence, as the basis for establishing the authorized depreciation expense. We believe the approach that we have pursued with total employee compensation studies, where the utility and ORA agree in advance upon study parameters and the selection of an independent qualified expert, may provide an appropriate model for the development of such a depreciation study. We will direct SCE to pursue this approach for a depreciation study to be included in its next GRC. While the joint management of the study should be limited to SCE and ORA, we recognize the important role fulfilled by TURN with respect to depreciation in this GRC, and we seek to ensure that TURN and other interested parties have an opportunity to participate appropriately in the study design. Toward that end, SCE should, at the outset of the study design process, convene a workshop providing opportunity for interested parties to participate. We urge and expect the parties' cooperative efforts toward the objective of a reliable, independent depreciation study.

### 9.3. SONGS 2 & 3 Remaining Life

There are no Pressurized Water Reactors (PWRs) in the United States that have operated for longer than 29 years without replacing steam generators. Of 69 operating PWRs in the United States with steam generators, 60, including SONGS 2 & 3, have first generation "alloy 600" tubing material that is subject to degradation. Of these 60 PWRs, 46 have either replaced steam generators or have replacement programs underway. At 30 PWRs where replacement has been completed, the average plant age at replacement was 16 years. At 16 PWRs where replacement is underway, the average age when replacement occurs is 26 years. The average age of PWRs without announced replacement plans, including SONGS 2 & 3, was 19 years in 2002.

Replacement of steam generators typically is performed when forecasts of maintenance and repair costs exceed the amortized benefits of the reduced costs achievable with the replacement steam generators. One of the costs of continuing to use the original steam generator is the reduced output that occurs as tubes are removed from service. Steam generators are manufactured with around 10% excess tubes to allow some to be removed from service without affecting unit performance, but the excess is generally used up for those plants considering replacement. SCE has set a 25% plugging level as the technical end of life of the SONGS steam generators, and its forecasts indicate that this level will be reached at approximately 2012.

SONGS 2 & 3 will have operated for 29 years in 2012 and 2013, respectively. SCE asks that the Commission establish the year 2012 as the end of the remaining useful life of SONGS 2 & 3 because the steam generators are only forecast to continue to operate with certainty through 2012. SCE maintains that its recommendation is consistent with proper accounting and depreciation principles that dictate a consistent matching of depreciation life with the associated investment.

TURN and ORA both recommend that the Commission establish the depreciable life for SONGS 2 & 3 equal to the remaining NRC operating license period (through 2022). ORA notes that the replacement of steam generators is uncertain, while there are no such uncertainties with the NRC license life.

***Discussion***

SCE has demonstrated that the need for steam generator replacement is probable for both SONGS 2 & 3 in, or near, 2012. However, even though it is reasonably foreseeable that the steam generators will require replacement at or about that time, SCE has not demonstrated how or why that eventuality supports the proposition that the remaining useful economic life of the SONGS units will be over at that time. As TURN has pointed out, many utilities have replaced steam generators and continued operating their plants. A unit of Palo Verde is expected to remain open after a steam generator replacement within the next several years. Both the cost and length of time for steam generator replacement appear to have been declining in recent years.

SCE's position rests on the implicit assumption that replacement of the steam generators will be uneconomic, but SCE has not presented sufficient economic analysis to support the proposition that SONGS 2 & 3 will have concluded their useful economic life by 2012. We therefore adopt the ORA / TURN proposal to use the life of the NRC license as the basis for SONGS 2 & 3 depreciation in this GRC. We note that there will be an opportunity to evaluate the economics of SONGS 2 & 3 steam generator replacement, and the implications for depreciable life, in a future GRC.

### 9.4. Easements

While it does not currently do so, SCE is proposing to begin amortizing rights-of-way for T&D line easements as well as general plant easements in this GRC. Based on discussions with other electric utilities, the majority of which amortize line easements between 50-75 years, SCE selected a 60-year amortization period. SCE estimates annual expenses of $1.734 million for transmission easements and $753,000 for distribution easements.

ORA contends that easements are non-amortizable costs and proposes that SCE's request be denied. In response to SCE's contention that PG&E and SDG&E amortize easements, ORA contends that decisions authorizing those utilities to do so are inconsistent with accounting rules for easements. ORA also contends that SCE has not shown the extent to which retirements are occurring.

***Discussion***

SCE has demonstrated that amortization of easements is permissible under the Uniform System of Accounts, which provides that assets exhibiting loss in service value will be depreciated. SCE states in its rebuttal testimony that it is now experiencing retirements associated with easements, and contends that this demonstrates that easements experience loss in value. However, SCE has not presented any information or analysis regarding the extent to which easement retirements are occurring. If the retirement of easements has become a significant factor that justifies a change in current practice for SCE, it would have been appropriate for SCE to mention that fact and provide supporting data in its direct testimony. SCE did not do so. We conclude that SCE has failed to sustain its burden of proof with respect to this issue, and therefore deny this proposal.

## 10. Other Results of Operations Issues

With respect to various results of operations issues, the parties have either not taken issue with SCE's GRC request or have reached agreement with SCE. No party took issue with SCE's showing on historical and projected productivity growth. SCE stipulated to ORA's sales forecast of 79,795 GWh, which relied on more recent information. SCE and ORA agreed to use the same methodology for cost escalation, and they derived a single set of cost escalation estimates for use in this proceeding. Exhibit 312 reflects the joint position of SCE and ORA with respect to escalation factors as of January 27, 2003, and the update testimony in

Exhibit 412 reflects the parties' joint position on escalation rates as of May 9, 2003. TURN initially challenged SCE's computation methods for payroll taxes, but in its rebuttal testimony SCE reduced its estimate of payroll taxes by $6.2 million. TURN now agrees with the computation method shown by SCE in its rebuttal testimony.

***Discussion***

There are no remaining disputed issues with respect to the results of operations topics noted above. SCE's showing on productivity is accepted; a sales forecast of 79,795 GWh is adopted; the cost escalation factors in Exhibit 412 shall be applied; and SCE's revised estimate of payroll taxes is adopted.

On April 11, 2003, in a letter to the Assigned ALJ, SCE identified errors in the results of operations model used in this GRC. The identified errors pertain to incorrect escalation of PBOP costs affecting both 2004 and 2005. The 2003 revenue requirements that we authorize herein are not impacted by the errors. As discussed in the following section, we approve a mechanism for authorizing SCE's revenue requirements for 2004 and 2005. The mechanism provides for future filings by SCE, which filings shall reflect the necessary corrections to the model used to calculate the revenue requirement.

## 11. Post Test Year Ratemaking

### 11.1. Introduction

SCE proposes to return to a conventional three-year GRC cycle beginning in 2003, and thus proposes to file another GRC for a 2006 test year. In conjunction with this proposal, SCE proposes a ratemaking mechanism for 2004 and 2005 that is drawn from elements of previously authorized GRC attrition and PBR mechanisms. SCE states that this "Post Test Year Ratemaking" (PTYR) mechanism is intended to provide additional revenues to cover its costs of doing business in 2004 and 2005. It includes a proposal for recovering the significant capital costs of its infrastructure replacement program.

No party contests the principle of some form of post-test year ratemaking adjustment for SCE. However, ORA opposes two aspects and Aglet opposes several aspects of SCE's PTYR proposal. Aglet's recommendations are more comprehensive and, in effect, constitute an alternative recommendation.

Section 11 of this decision addresses the various aspects of SCE's and Aglet's PTYR proposals except for proposals regarding performance incentives, which are addressed in Section 13. Section 11.2 addresses SCE's revenue balancing account proposal. Section 11.3 addresses the need for a PTYR mechanism and the related question of whether it should apply to 2004 and 2005 or to 2005 only. As explained in Section 11.3, we find that adoption of a PTYR mechanism is justified for this GRC cycle. The remainder of Section 11 addresses the appropriate elements of the mechanism. Sections 11.4 through 11.9 address, respectively, productivity adjustments, SONGS 2 & 3 planned outage costs, capital costs, O&M escalation, so-called "Z-Factors," and filing procedures.

### 11.2. Revenue Balancing Account

Section 739.10 (added by Stats. 2001, 1st Ex. Sess., Ch.8, Sec. 10) provides that "[t]he commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations." Pursuant to this statute, in D.02-04-055, the Commission approved a revenue balancing account mechanism that assures recovery of SCE's authorized distribution revenue requirement under the PBR mechanism. SCE proposes in this GRC to utilize such a revenue balancing account during the test year and beyond to adjust for variations in sales.

NRDC strongly favors revenue-based ratemaking mechanisms because they align shareholder and ratepayer interests in favor of economically and environmentally efficient decisions rather than reward utilities for increasing commodity sales. NRDC supports SCE's proposed continuation of its revenue balancing account mechanism along with expansion to include all GRC related costs not subject to other balancing account mechanisms. NRDC submits that this is consistent with Section 739.10 and ensures that SCE's revenues are not tied to electricity throughput.

To the extent that the Commission approves any post-test year ratemaking relief, Aglet supports revision of the authorized revenue requirements, as opposed to rates, in order to implement Section 739.10 and mitigate incentives for SCE to promote sales.

***Discussion***

NRDC's concern is ensuring that SCE is not rewarded for increasing commodity sales, an objective implicit in Section 739.10 and one that we share. A revenue balancing account mechanism is consistent with this objective. No party opposes the use of a revenue balancing account, and we will approve SCE's proposal for such a mechanism.

However, we note that the need to establish an authorized annual revenue requirement for 2004 and 2005 in connection with the revenue balancing account does not mean, as SCE suggests, that the establishment of a particular post-test year ratemaking mechanism is required to determine annual revenue requirements. In other words, the objective of removing incentives to increase commodity sales does not require that an attrition allowance or other form of revenue requirement adjustment be established. Whether or not it is advisable to do so, it would be possible to apply the authorized test year revenue requirement to the following years. SCE's PTYR proposal will be evaluated on its merits, not on the basis that it is somehow required under Section 739.10 or D.02-04-055.

### 11.3. SCE's and Aglet's PTYR Proposals

SCE's PTYR proposal would be implemented through annual advice letter filings and, in addition to service quality performance incentives, would include four principal elements: (1) adjustment of O&M expenses based on the GRC escalation rate methodology, i.e., forecasts of labor and nonlabor escalation rates; (2) adjustment of capital-related costs based on budgeted construction expenditures; (3) adjustment of generation costs to reflect planned outages at SONGS 2 & 3; and (4) allowance for Z-Factor adjustments following major exogenous events.

SCE's direct testimony indicated that its PTYR mechanism would result in a projected revenue requirement decrease of $78.239 million in 2004 and an increase of $115.899 million in 2005, respectively, based on then-current price inflation forecasts. (Exhibit 65, pp. 2, 19.) However, this includes the effects of transferring SONGS 2 & 3 from the ICIP mechanism to conventional cost of service ratemaking beginning in 2004, and is therefore not particularly explanatory. Using data provided by SCE (Exhibit 111), Aglet determined that by excluding the effects of SONGS 2 & 3 ICIP revenue, SCE's PTYR proposal would increase 2004 authorized revenue requirements by $154.6 million or 5.1% over the 2003 amount, and would increase 2005 authorized revenue requirements by $142.5 million or 4.5% over the 2004 amount.[59] In any event, SCE proposes to update its revenue requirement projections based on updated price inflation

[59] In its May 2003 update testimony (Exhibit 411, p. 3), SCE estimates revenue requirements of $3.452 billion for 2004 and 3.617 billion for 2005.

forecasts that will be made in annual advice letter filings. These annual filings would also include an adjustment for the cost of planned outages at SONGS 2 & 3, as addressed in part in Section 3.1.3 of this decision.

Aglet's primary recommendation is for a 2005 adjustment to SCE's authorized 2003 revenue requirement. With the exception of SONGS 2 & 3 outage costs, Aglet opposes any adjustment for the year 2004. The 2005 adjustment would be based on the change in the U.S. Bureau of Labor Statistics Consumer Price Index -All Urban Customers (CPI) plus a SONGS 2 & 3 adjustment and a limited Z-Factor allowance. To illustrate the impact of this proposal, Aglet used the 2003 revenue requirement requested by SCE and the CPI change from October 2001 to October 2002, and determined that the 2005 revenue increase would be $61 million.

Aglet's secondary recommendation is for a year 2005 attrition adjustment based on: (1) expense escalation using ORA's labor and nonlabor escalation factors; (2) plant additions calculated from historical averages, as in past attrition mechanisms; (3) SONGS 2 & 3 outage adjustments; and (4) a limited Z-Factor allowance covering postage rate increases and new government mandated programs.

***Discussion***

Whether called attrition or known by some other name, proposals such as SCE’s PTYR mechanism have been approved in energy utility rate proceedings on several occasions over the past 20 years, but not invariably so. Attrition allowances for non-test years, and by extension SCE’s PTYR proposal, are neither automatically granted nor are they entitlements. They are not intended to insulate utilities from economic pressures that all businesses experience.

We start with the proposition that a utility's opportunity to earn a fair return on the investments made to provide adequate utility service is realized with the adoption of a just and reasonable forecast test year revenue requirement. Then, to judge whether post-test year revenue adjustment provisions are appropriate, we inquire into whether there are, or will be, conditions that might undermine a utility's opportunity to earn its authorized rate of return after the test year. Such conditions need not be limited to those encountered 20 years ago, when the Commission was approving attrition adjustments because of high costs of utility debt and because the economy was unpredictable and volatile. Interest rates may be lower and the economy may be more stable now, but that does not mean there can be no other conditions that impact the utility's ability to earn a reasonable return.

With a revenue balancing account, variations between recorded revenues and the utility's authorized revenue requirement are tracked for subsequent recovery from, or refund to, ratepayers. Any additional revenues beyond the authorized revenue requirement that result from customer growth or increased usage per customer are returned to customers as a rate decrease. They are not available to offset any cost increases. SCE contends that in order for it to have a fair opportunity to earn its authorized return on equity, we should provide for an increase in the authorized annual revenue requirement so it can recover cost increases caused by customer growth, the need to replace aging infrastructure facilities, and the impact of price inflation on operating expenses.

Regarding the impact of a revenue balancing account, SCE paints only a partial picture by failing to note that the account protects it against any revenue shortfalls that might otherwise occur if usage declines. Nevertheless, even considering the full picture, we are persuaded that the use of a revenue balancing account provides added, though not full, justification for a revenue requirement adjustment mechanism such as those proposed by SCE and Aglet.

The rationale for approving non-test year revenue requirement adjustments is greater in this GRC than we have encountered in recent proceedings where we denied such mechanisms. SCE's financial condition was devastated by the events of 2000 and 2001, and it only narrowly avoided bankruptcy. While SCE's earnings have improved since the worst of the energy crisis in 2000 and early 2001, SCE is still working to regain full creditworthiness, an objective that no party opposes and one that this Commission has repeatedly endorsed. This weighs strongly in favor of adopting a revenue requirement adjustment mechanism for this GRC cycle for both 2004 and 2005.

Aglet notes that no other major California electric utility will receive an attrition adjustment in 2003. While perhaps literally true, we note that SDG&E filed for an attrition-like increase pursuant to its PBR mechanism. In any event, for the reasons discussed earlier, the fact situations of other utilities are not necessarily the same as those considered here, and whether other utilities have received attrition increases is of little import in this case.

To provide SCE with a reasonable opportunity to earn the authorized return on utility investments during this GRC cycle, we will adopt a PTYR mechanism applicable for both 2004 and 2005. Subject to the revisions discussed in the remainder of Section 11, we favor the framework of the PTYR mechanism advanced by SCE over the primary and secondary proposals of Aglet. Aglet's primary recommendation relies on an inflation adjustment applied to SCE's base rate revenue requirement. This approach may be simple, but it has no other known benefit. Simplicity alone does not prompt us to prefer it over SCE's approach, which provides for separate and therefore, we believe, more accurate treatment of O&M expenses and capital related costs. Aglet's secondary recommendation is generally similar to SCE's framework, and the differences are addressed below.

Appendix D shows, for illustrative purposes, the revenue requirement impacts of the PTYR mechanism using current assumptions. The revenue figures in Appendix D are not directly comparable to those in Appendix C due to the impact of transferring SONGS 2 & 3 from ICIP to cost-of-service ratemaking.

### 11.4. Productivity Adjustment

Aglet appears to find fault with SCE's proposal because it makes no provision for productivity in its expense escalation method.[60] Aglet notes that the Commission has historically assumed that productivity achievements should offset customer and sales growth. Aglet also notes that SCE's current PBR includes a productivity adjustment with an imputed rate of 1.6%.

SCE responds that Aglet mischaracterizes the effect of productivity on the need for a post-test year ratemaking mechanism. SCE also submits that Aglet complicates its recommendation with a reference to productivity associated with the PBR.

***Discussion***

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[60] It is not entirely clear that Aglet considers SCE's omission of a productivity adjustment to be a fault. In its direct testimony (Exhibit 246), in a discussion under the heading "Expenses," Aglet proclaims (at p. 5) that "[t]here are two problems with SCE's expense escalation method." After completing a description of those two problems, Aglet goes on to discuss SCE's omission of a productivity adjustment. Although it might be reasonable to conclude that Aglet does not consider this omission to be a problem, we attribute the confusion to a drafting error and assume that Aglet does indeed find the omission problematic.

SCE's testimony is that the company's annual average productivity from 1986 to 2000 ranged from 0.56% to 0.88% depending on output measure, that a similar rate of productivity may not be achieved in the test year, and that its productivity will be below price inflation after the test year. SCE's testimony further indicates that revenue requirements will increase as a result of the costs of serving new customers. Combined, these two factors, i.e., low productivity gains and customer growth cost impacts, justify SCE's proposal to exclude a specific productivity adjustment from its PTYR mechanism in this GRC cycle.

### 11.5. SONGS 2 & 3 Outages

In addressing generation issues we approved SCE's proposed flexible outage schedule ratemaking mechanism for SONGS 2 & 3 and a per-outage O&M estimate of $52.462 million (2000 dollars, 100% share). A component of that mechanism is SCE's proposal to forecast outage O&M costs in annual PTYR filings based upon the adopted outage cost estimate and a forecast of the number of outages expected to occur in the next year. Aglet generally accepts this framework but recommends that it be limited to a single planned refueling outage at SONGS in 2004 and scheduled outages in 2005.

***Discussion***

The effect of Aglet's recommendation would be to limit SCE's cost recovery for SONGS 2 & 3 outages in 2004 to the adopted costs for one outage, even if more than one outage is reasonably forecast. It may be likely that there will be only one scheduled outage in 2004, but we will not impose such an arbitrary limit on SCE's cost recovery. However, in any PTYR filing in which it includes costs for SONGS outages that it forecasts will occur in the following year, SCE shall include a proposal for refunding to ratepayers the costs of any outage that was forecast and included in rates but did not occur in that year.

### 11.6. Capital Forecasting Methodology

SCE's proposed PTYR mechanism uses detailed, budget-based estimates of capital additions in 2004 and 2005. SCE contends that it must now make up capital spending that was deferred due to the crisis of 2000 and 2001. In addition, SCE contends, its infrastructure replacement program will significantly increase its required investment in transmission and distribution plant. Thus, according to SCE, its capital spending is reasonably expected to be much higher than a forecast based on historical spending would indicate.

ORA and Aglet oppose the use of a budget-based approach. ORA proposes using seven-year historical averages as the basis for capital additions in the post-test years, a practice applied for estimating plant additions in past attrition allowances for SCE. ORA's approach yields a plant additions estimate of $888 million for 2004, or $419 million less than SCE's estimate of $1.307 billion; and an estimate of $905 million for 2005, or $238 million less than SCE's estimate of $1.143 billion. Aglet's primary recommendation is to simply adjust revenue requirements by an inflation escalator, and its secondary recommendation mirrors ORA's proposal for the use of historical plant additions data.

ORA notes that use of a budget to derive capital related costs has never been part of any previous attrition or PBR mechanism, and that the problem of a budget based forecast is greater here because SCE used 2000 budget data that has proved inaccurate for 2000 and 2001. Aglet presents several reasons to reject a budget-based approach, including the following:

- Allowing rate changes based on budgets would have the effect of allowing large blocks of capital into rates without meaningful review.
- The record does not support a finding that SCE's Board of Directors has actually approved the amounts in SCE's PTYR proposal.

- Allowing budgeted costs in rates would give SCE strong incentives to inflate its spending plans without real intention to build, or to delay startup of needed plant construction.
- Long-term budgets do not provide reliable, sound estimates of future plant additions.

***Discussion***

ORA and Aglet raise important concerns regarding SCE's budget-based approach to forecasting PTYR capital costs, which yields forecasts that are $419 million greater in 2004 and $238 million greater in 2005 than the spending levels predicted by SCE's actual experience. As we have repeatedly observed in this decision, there is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned.

On the other hand, SCE has demonstrated persuasively that a PTYR forecast based solely upon historical averages may understate the reasonable capital spending needs for the PTYR period of this GRC cycle, assuming that SCE actually carries out its spending plan. We note that no issues have been raised as to the reasonableness of any projects included in SCE's budgets; the parties question whether SCE's capital budget will be fully implemented.

When older facilities are replaced with new ones, the associated costs are typically much higher than what is included in rates for the original facilities. Moreover, the effect of this phenomenon is enhanced by the accelerated pace of planned capital spending associated with the SCE's infrastructure replacement program. The use of historical capital spending incorporates the lower capital additions from SCE's financial crisis years, and it may not adequately reflect the increased pace of capital investments associated with the infrastructure replacement program.

We find that both the SCE and the ORA / Aglet approaches to forecasting PTYR capital costs have significant attendant problems, and we are not prepared to adopt either in its entirety. We will instead adopt a methodology for PTYR capital costs that combines elements of both approaches, as follows. We adopt ORA's forecasts for 2004 and 2005 as a baseline along with SCE's budget-based forecasts. SCE will be authorized to include the capital costs associated with its budget-based forecast in its PTYR filings, with any adjustments needed to reflect adopted capital expenditures, but rates (or revenue requirements) will be subject to refund to the extent that they exceed rates (or revenue requirements) that would be associated with the baseline forecast. Thus, to the extent that SCE fully implements its respective capital spending budgets for 2004 and 2005, it will be able to recover the associated costs through the PTYR mechanism, subject to review in SCE's next GRC. SCE's PTYR filing shall include a proposed accounting mechanism to implement this approach.

We believe that this hybrid approach mitigates the vagaries of budget-based ratemaking and adequately addresses the legitimate concerns raised by ORA and Aglet. SCE's 2004 and 2005 capital additions will still be subject to review in SCE's next GRC. Also, if SCE's Board of Directors rejects a planned project that was reflected in SCE's budget, and SCE therefore does not spend its full budget, ratepayers are protected from paying phantom costs. It removes incentives to inflate spending plans. At the same time, this hybrid approach provides reasonable opportunity for SCE to earn its authorized return up to the limits of its own budgets.

### 11.7. Escalation Factors

SCE proposes separate labor and non-labor escalation factors drawn from various sources such as DRI-WEFA (which in October 2002 changed its name to

Global Insights), a commercial provider of such economic data. SCE proposes separate escalation rates for health care costs. Aglet finds fault with SCE's method because the results do not compare well with general measures of inflation in the U.S. economy, and because such general inflation measures already include health care price inflation.

***Discussion***

The CPI may be a simple, accessible measure of general inflation faced by urban U.S. consumers, but that alone does not make it appropriate as a measure of price changes faced by an electric utility. It does not specifically cover the prices of the typical goods SCE purchases. Conversely, SCE's proposed escalation rates were not designed to track the general level of inflation, and there is no reason why they should do so. Moreover, even if the CPI includes health care price inflation faced by consumers, it excludes the prices of health care paid for by employers.

Apart from simplicity (and the fact that it yields a lower revenue requirement), Aglet has not demonstrated why it is appropriate to forecast SCE's cost changes using a measure of price changes faced by consumers instead of measures of price changes faced by utilities. SCE's escalation approach more accurately reflects utility purchases and will therefore be approved.

### 11.8. Exogenous Cost Changes (Z-Factors)

In SCE's existing PBR mechanism, Z-Factors are exogenous events that result in a major cost impact on the utility. The existing Z-Factor mechanism allows either SCE or ORA to submit a letter of notification to the Commission's Executive Director to identify any potential Z-Factor event. SCE is at risk for events that do not have a revenue requirement impact of more than $10 million, and there is a $10 million "deductible" applied on a one-time basis to the first year's revenue requirement associated with any approved Z-Factors. Costs associated with municipal utility formation and Section 463 projects are treated as Z-Factors but without the $10 million threshold or the $10 million deductible.

SCE proposes to continue this mechanism in the PTYR period. No specific Z-Factors have been identified during the PBR period, but SCE believes that the mechanism has nonetheless provided assurance that a clear process is in place to address unanticipated major variations in SCE's costs.

Acknowledging that such a mechanism makes some sense in the context of a long-term PBR mechanism, Aglet nevertheless opposes continuation of the Z-Factor mechanism as unnecessary in the context of a three-year GRC cycle. In addition, Aglet would limit Z-Factors to postage rate changes and the costs of new government-mandated programs.

***Discussion***

Although the Z-Factor mechanism was an innovation associated with the PBR program, and no similar approach was followed in previous GRCs, we believe it is reasonable to continue this mechanism as part of the PTYR mechanism with the return to more conventional cost-of-service ratemaking. As SCE points out, if a major change in tax law were to reduce its tax liabilities during 2004, we might seek to reduce SCE's rates so that these benefits flow to customers prior to SCE's next GRC test year in 2006. Not unreasonably, SCE expects similar treatment in the event of a major exogenous increase in its costs. We will approve SCE's proposed mechanism for exogenous cost changes.

Aglet takes issue with the $10 million per event threshold, but it was litigated and approved by the Commission in establishing the PBR mechanism. No superior threshold proposal has been advanced in this proceeding.

### 11.9. Filing Procedure

As noted earlier, SCE proposes that the PTYR mechanism be implemented by advice letter filings. Aglet agrees that this is acceptable if the Commission approves Aglet's simple, CPI-based formula. If the Commission approves SCE's ratemaking proposal, then Aglet believes that SCE should file an application that includes updated escalation forecasts, demonstrated approval of specific capital budgets by SCE's Board of Directors, and SONGS 2 & 3 refueling schedules. Aglet believes that the advice letter process would not allow adequate review of the details of SCE's expenses, capital-related costs, and SONGS 2 & 3 refueling plans.

***Discussion***

The Commission has typically allowed attrition filings to be accomplished through the advice letter process, although there have been exceptions where attrition applications have been required. With respect to factors affecting revenue requirements, it appears that Aglet seeks the more comprehensive review of a formal application where utility discretion and judgment are involved. Aglet appears to agree to the simpler advice letter process where straightforward application of a formulaic approach is involved.

We generally concur with Aglet's construct, i.e., that formal applications should be required where greater utility discretion and judgment is involved in a filing. However, we note that Aglet suggests there are three areas of potential cost impacts that justify the requirement for formal applications: expenses, capital-related costs, and SONGS 2 & 3 refueling plans. With the PTYR mechanism that we are adopting, none of these areas provide significant opportunity for the unmitigated exercise of utility discretion that would require the detailed review of an application. First, PTYR filings would involve only a review of the escalation factors used to adjust expenses found reasonable in this decision, not an additional detailed review of the expenses themselves. We note that SCE and ORA have repeatedly agreed upon such escalation factors in this proceeding, and that there has been little if any dispute regarding them. This suggests that updating the escalation factors used in this decision does not require a formal application. Second, our hybrid approach to capital additions forecasts adopts forecasts that are in this record, and it provides for an accounting true up. Third, our adopted approach to cost recovery for SONGS 2 & 3 planned outages also provides for a true-up, protecting ratepayers against possible forecasting errors.

Accordingly, as to the reasons presented by Aglet, we find insufficient justification for requiring that formal PTYR applications be filed. However, Aglet's analysis in this proceeding prompts us to require formal PTYR applications under certain circumstances. When the effects of converting SONGS 2 & 3 to cost-of service ratemaking are isolated, the PTYR mechanism could yield base rate revenue requirement increases on the order of $150 million, or approximately 5%. As a matter of policy, we are unwilling to relegate PTYR rate increases of a greater magnitude to the streamlined review of the advice letter process. We will therefore permit SCE to file for PTYR adjustments through advice letters unless the proposed increases exceed $150 million or 5%, in which case a formal application shall be filed.

## 12. Jurisdictional Allocation Method

The expenses and capital-related costs examined in this GRC are presented on a total system basis, i.e., they include both Commission and FERC-jurisdictional components. Certain costs, including A&G expenses and General and Intangible (G&I) plant costs, must be split into Commission and FERC jurisdictional amounts. SCE allocated A&G and G&I costs between the Commission and FERC jurisdictions using the "labor allocation" method employed by FERC. ORA recommends the "multifactor cost allocation methodology," which would allocate as much as $22 million more to the FERC jurisdiction than the labor allocation method favored by SCE, depending on assumptions used. As shown in the Joint Comparison Exhibit (Exhibit 403, p. 43), the difference in revenue requirement attributable to this issue could be as small as $1.957 million.

***Discussion***

The Commission recently resolved issues pertaining to the labor and multifactor allocation methods in D.03-08-062, issued in SCE's A.01-02-030. The Commission authorized SCE to recover costs booked to the Transmission Revenue Requirement Reclassification Memorandum Account (TRRRMA), having determined that those costs were distribution related. Since costs booked to the TRRRMA were determined pursuant to the labor allocation method used by FERC, the Commission in effect approved that method.

A decision was pending in A.01-02-030 when briefs were filed in this proceeding. ORA recommended in its brief that the principles from that decision be used as the basis for allocating A&G and G&I costs for this GRC. Consistent with D.03-08-062, as well as ORA's recommendation, we will approve SCE's proposal to use the labor allocation method in this GRC.

## 13. Performance Incentives

### 13.1. Introduction

"Performance incentives" are proposed ratemaking mechanisms that potentially reward and/or penalize the utility financially depending on whether it meets, exceeds, or fails to meet pre-established performance benchmarks.[61]

SCE states in its opening brief that maintaining a balanced reward/penalty safety mechanism would signal that the Commission is interested in encouraging further improvement in SCE's safety performance. (SCE opening brief, pp. 276-277.) Adopting performance incentives for safety and for reliability is not the only way to signal our interest. We state without equivocation that we are interested in encouraging further improvement in the safety and quality of SCE's system, and it is our intent in this GRC to approve a revenue requirement that enables SCE to achieve reasonable system safety and reliability. We fully expect SCE's managers will give the proper attention to this area of performance, as we expect they will in the areas of reliability, customer satisfaction, and telephone response times.

The commission has regulatory mechanisms for addressing deviations from expected levels of service, including penalties, ratemaking enhancements or disallowances. But many of these mechanisms are based on backward-looking performance reviews. A properly structured incentive program that is layered on top of cost-of-service ratemaking as we intend to practice it can be a targeted regulatory mechanism that promotes improvement and discourages

[61] These ratemaking penalties are not the same as non-compliance penalties such as those discussed earlier in connection with TURN's proposed penalties for SCE's past pole inspection practices.

retrogression in these important areas as these deviations occur. We will approve the benchmark performance standards recommended by CUE in its initial testimony[62] so that we have a set of conventional statements about our expectations for the most important areas of service adequacy. These are:

- Safety -- An OSHA recordables rate of 3.70
- Outage Duration – 50 minutes of SAIDI (System Annual Interruption Duration Index) as proposed to be redefined by Edison
- Outage Frequency – 0.97 SAIFI (System Annual Interruption Frequency Index) as proposed by Edison
- Momentary Outages – 1.22 MAIFI (Momentary Annual Interruption Frequency Index)

We will approve the incentive mechanism as proposed by CUE, without deadbands, as best reflecting our intention that Edison have a set of financial incentives to continually improve performance. In effect, the utility will be authorized to increase its revenues if it performs better than the relevant benchmark, and it suffers a revenue loss if it fails to achieve the benchmark performance level.

### 13.2. Parties' Proposals

In this GRC parties have proposed performance incentives for system reliability, employee safety, customer satisfaction, and telephone response times.

SCE included within its T&D testimony a proposed new Service Reliability Mechanism based on the duration and frequency of outages, similar to SCE's

[62] Exhibit 257, Testimony of David Marcus, revised December 6, 2002.

existing PBR reliability mechanism. (Exhibit 23, pp. 27-37.) The total Service Reliability reward or penalty for which the company would be at risk is $30 million. The underlying policy objective is for SCE to maintain historical reliability levels. (Exhibit 21, p. 8.) SCE states that the mechanism is proposed, "to provide the Commission and [SCE's] customers with the assurance that SCE has the proper incentive to maintain [the level of service reliability achieved over the past 10 years] in the future." (Exhibit 23, p. 27.)

Consistent with the objective of maintaining a safe and healthy working environment, SCE included within its A&G testimony a proposed Employee Safety Mechanism with a $5 million penalty / reward component. (Exhibit 45, pp. 33-39.) SCE believes that the Commission "should provide a corporate incentive to maintain and improve worker safety." (*Id.*, p. 33.)

SCE included within its Customer Service Operations testimony a proposal to continue the customer satisfaction performance incentive adopted in D.96-09-092. (Exhibit 37, p. 79.) SCE maintains that this incentive, under which it can be rewarded or penalized up to $10 million annually, is an effective means to improve customer satisfaction. (*Id.*)

ORA recommends that there be no rewards for reliability performance or for employee safety, i.e., ORA proposes penalty-only incentives. With respect to reliability, ORA notes that SCE has no programs specifically designed to improve reliability. ORA contends that SCE should not be rewarded "for performance levels achieved incidentally with no effort on its part." (Exhibit 229, p. 6-2.) With respect to employee safety:

> …ORA believes that one of SCE's objectives should be to improve and maintain reliable worker safety standards and programs without having to be paid incentives. Furthermore, through utility rates, SCE's captive ratepayers that are required to pay for basic

> service, already fund SCE's employee safety maintenance programs and should not be forced to pay excessive incentives to ensure that SCE continues to maintain a safe and healthy working environment for its employees. (Exhibit 114, p. 14-D-10.)

Among other things, CUE proposes principles and policies that would apply to performance incentives. For example, CUE opposes the use of deadbands, i.e., ranges of outcomes for which no reward or penalty is assessed. On the basis of these principles and policies, CUE offers several proposed revisions to SCE's proposed incentives for reliability and safety. The most important modifications are calibrating the indexes to reflect recent levels of performance as measured by the indices, and the elimination of deadbands to make the mechanism more sensitive to deviations. We adopt CUE's starting measures for the indices.

CUE and Edison proposed identical reward/penalty rates for deviations in SAIDI and SAIFI: $2 million/per average annual minute deviation for SAIDI and $1 million/ per 0.01 annual frequency deviation for SAIFI. We will approve these numbers. CUE proposed a reward/penalty rate of $50,000 for each deviation of 0.01 in the OSHA recordables rate. We will approve this number. No other party made a recommendation. CUE proposed a reward/penalty rate of $200,000/ per 0.01 annual frequency deviation for MAIFI. We will approve this number. No other party made a recommendation.

TURN defers to CUE's proposals with respect to safety and reliability standards. However, due to diminishing returns to additional service quality improvements, TURN does not embrace unlimited application of CUE's principle that improvements relative to a performance benchmark deserve to be paid for by ratepayers. TURN opposes SCE's proposal to base a customer satisfaction incentive on customer surveys. TURN recommends that the Commission establish a mandatory telephone response standard of 75% of responses within 50 seconds, subject to a schedule of penalties.

Noting that SCE's performance incentive proposals were not informed by any cost-effectiveness study, Aglet opposes those proposals. Aglet believes that rewards gained through such incentives depend more on design of incentive formulas than incremental improvements in performance attributable to the incentives.

After the conclusion of hearings and briefing, SCE and CUE filed a joint motion for approval of a settlement of issues pertaining to the proposed performance incentives for employee safety and distribution reliability. ORA opposes the settlement on both procedural and substantive grounds. We also decline to approve it.

***Discussion***

Performance incentives such as those at issue here are a relatively recent regulatory phenomenon for California electric utilities. They were first adopted in connection with the Commission's 1990's experimentation with PBR as an alternative to conventional cost-of-service ratemaking. For example, in 1994, in D.94-08-023, the Commission adopted a PBR proposal for SDG&E that included performance incentives to "reward or penalize the utility's ability to control employee safety, system reliability, and customer satisfaction." (55 CPUC 2d 592, 633.) The Commission adopted performance incentives in connection with PBR mechanisms for SCE in 1996 (D.96-09-092; 68 CPUC 2d 275) and for SoCalGas in 1997 (D.97-07-054; 73 CPUC 2d 469). In D.99-09-030 the Commission adopted a second-generation PBR for SDG&E that included performance incentives. In adopting SCE's PBR, the Commission stated the following:

> Thus, we see PBR as emulating the competitive process to encourage utility management to make decisions which resemble an efficient or competitive outcome. An efficient utility will control rates which benefits ratepayers. However, we want to ensure fairness to ratepayers, employees and shareholders in the PBR process. This requires balancing potentially conflicting interests. The utility can increase short run profits through reducing variable costs, but without revenue sharing such cost reductions will not lower rates. Moreover, such reductions not only can affect staff immediately but the service quality impact may only appear much later. [¶] In this PBR for Edison, we balance these interests by requiring a progressive sharing of net revenue between shareholders and ratepayers and by having both the productivity and service quality measures increase over the duration of the PBR. (68 CPUC 2d 275, 290.)

> In adopting the SoCalGas PBR, the Commission observed that the utility had proposed a service quality mechanism "[i]n order to ensure that SoCal's focus on increased productivity through cost reductions does not have a deleterious effect upon the quality of service . . . during the period when the PBR rates are in effect." (73 CPUC 2d 469, 490.)

We have rejected performance-based ratemaking for energy utilities in favor a transparent regime of cost-based ratemaking. Consequently it may appear anomalous to borrow targeted performance incentives from the obsolete PBR regime. Performance incentives mechanisms may add complexity to regulation and ratemaking. They can be controversial, as evidenced by the extent of litigation and lack of agreement among the parties over how to construct them, even after two of the parties reached a settlement agreement. Moreover, even if they are reasonably calculated to promote a specific regulatory objective, performance incentives could work at cross-purposes with other regulatory objectives or have other unintended consequences. For example, incentives that are intended to improve reliability by reducing the number of circuit interruptions might be inappropriate, even if effective, if they added unduly to ratepayer costs.[63] CUE, a proponent of performance incentives, points out that improperly constructed incentives are worse than none. Aglet, an opponent of SCE's proposed incentives, points out that such incentives can lead managers to make non-optimal resource allocation decisions.

Nevertheless, we will approve a set of targeted performance incentives, both positive and negative, because they provide a more responsive approach to deviations in service adequacy and quality than our other ratemaking mechanisms. As noted above, they were adopted to mitigate the potentially deleterious effects that the efficiency gains sought through PBR could have on service quality, including reliability, and on safety. They can be carefully adapted to the cost-of-service regime and enhance our ability to regulate in the public interest, providing both financial incentives to guide utility activities and an early warning of longer-term trends that we can use to guide more intrusive regulatory interventions such as complaints and investigations. They represent a calibration, not a contradiction, of our cost-of-service principles.

In the cost-of-service regime we attempt to determine the reasonable costs of adequate service and establish rates that cover those costs, including a reasonable profit. This entails describing the public's expectations about service quality, including performance benchmarks and standards, and providing revenues sufficient to pay for those service levels. In the cost of service regime we aspire to transparent accountability for revenues and costs, so that we can

[63] We have directed ORA and Edison to exploer how this issue might be addressed in the next GRC. See above, Section 4.3.

determine both the causes of failure to meet expectations and the resources needed to provide incremental improvements, if necessary.

We will consider whether the proposed performance incentives are necessary for achieving one or more of our regulatory objectives and are likely to be cost-effective; we do not believe that performance incentives should be adopted solely on the basis of their mere consistency with a particular objective. Since rates set through our conventional approach to ratemaking are intended to provide the funding required to meet the regulatory objectives of safe and reliable service, we must ask why the utility needs the possibility of additional ratepayer funding, or threat of reduced funding, to get the utility to do what it is already funded and expected to do. The burden is on the proponents of performance incentives to prove they are necessary, cost-effective, and otherwise reasonable.

As proposed by CUE, performance incentives are intended to be carefully layered on top of a rigorous cost-of-service approach to T&D operation, maintenance and capital spending . CUE has developed performance measures that accurately reflect current levels of utility performance in the areas of general employee safety, and service reliability as measured by the frequency and duration of outage events (SAIDI and SAIFI) and the frequency of "momentary" outage events (MAIFI). Deviations from these levels of performance are rewarded or punished, financially, as the deviations occur. We would expect that this focus on results measured more frequently than the General Rate Case permits will help Edison sustain its efforts.

In proposing performance incentives for reliability, safety, and customer satisfaction, SCE exposes itself to the inference that it may not perform reasonably in those areas even with the funding to do so. SCE believes that "penalty and reward values should be sufficiently large, such that they command the attention of [its] management." (Exhibit 23, p. 34.) However, we find that the evidence supports the proposition that SCE has sufficient incentive to provide "adequate" service through the cost-based rates we have authorized.

SCE cannot afford to disregard reliability, employee safety, customer satisfaction, or telephone responses. We note that SCE is "committed to maintaining reliable service to [its] customers" (Exhibit 23, p. 27) and that employee safety is a "top priority" (*Id.*, p. 37; also, Exhibit 21, p. 21). The performance incentives proposed by SCE and CUE are, at most, incremental to existing incentives to perform well. Further, a number of negative business consequences could ensue including threats of lawsuits; higher insurance premiums; bad publicity; loss of goodwill and other forms of corporate prestige; and, in the most extreme cases, loss of franchise or municipal takeover.

Even in the absence of additional incentives such as those under consideration, we can expect that SCE's managers will pay a great deal of attention to the company's performance in each of the areas for which incentives have been proposed.

SCE's Director of Business and Regulatory Planning, who is in charge of customer satisfaction among other things, testified that SCE was among the first utilities in the nation to implement a voluntary service guarantee program, paid for by shareholders and without any encouragement from the Commission. She contends that this "demonstrates SCE's ability to identify effective customer service options when they are called for." (Exhibit 297, p. 45.) If SCE has the ability to identify and implement customer service guarantees without Commission prodding or ratepayer funding, we need to know why the company requires extra ratepayer dollars over and above the funding needed to actually provide adequate customer satisfaction.[64]

SCE's Senior Vice President for the TDBU also testified that employee safety is SCE's top priority, and that SCE has a "strong focus on safety … that *significantly exceeds the level necessary to meet our PBR goals*." (Exhibit 21, p. 22, emphasis added.)

Ratemaking consequences attached to deviations from the established benchmarks should reinforce those incentives and lead to improved performance, accurately measured. In the employee safety area, for example, the goal – probably unattainable – should be perfect safety, not reasonable safety. We can strive for that goal, consistent with our other regulatory objectives. For this reason we do not approve ORA's suggestion that perfomance incentives should be only negative.

We note that the Public Utilities Code places employee well-being on the same level as the well-being of ratepayers and the public.[65] Making safety the top

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[64] Even though SCE opposed certain service guarantees because, among other things, they would add $534,000 in annual operating costs, SCE is content to have ratepayers pay for market research costs for the customer satisfaction survey needed for the customer satisfaction performance incentive. SCE's GRC request includes $1.540 million for market research. This is based on 2000 recorded expenses of $1.475 million plus $65,000 for mandatory surveys associated with rotating outages. Of the recorded expense of $1.475 million, approximately half, or nearly ¾ of a million dollars, is for developing customer satisfaction information needed to meet the reporting requirements of PBR. (Exhibit 37, pp. 78-79, 171.) Even though we are denying SCE's proposal to continue its customer satisfaction performance incentive, we will not order a reduction to the test year revenue requirement for this expense, since the performance incentives will remain through the end of the GRC test year. SCE should, however, remove the expense from its PTYR requests.

[65] Pub. Util. Code 451.

priority is therefore consistent with the public interest. Modest performance incentives that reinforce utility actions to create and sustain a safe place of work, as measured by objective criteria, are therefore no burden on the ratepayers.[66] Sustaining a safe place is a goal for the public, which we propose to recognize with the performance incentive program, just as we recognize that a reliable grid is an important public goal, which we intend to recognize through adoption of the reliability measurements and modest performance incentives.

## 14. Issues Raised by Commissioner Wood and the Energy Division

### 14.1. Introduction

Assigned Commissioner Carl Wood directed SCE and invited other parties to present testimony on several issues, mostly focused on positioning SCE to resume the provision of fully integrated utility service. Included among these topics were (1) an examination of SCE's organizational structure, internal resources, and decision-making processes for planning and investment activities; (2) safety, reliability, and maintenance standards; (3) customer service programs, including localized outreach; (4) an examination of policies for how SCE conducts its operations, including land use and land management practices; and (5) employee and supplier diversity.

We thank SCE and the other responding parties for their contributions in response to the Assigned Commissioner's requests. California energy utility

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[66] We also note that SCE contends that the single most significant factor in avoiding serious injuries is its workers' own focus on their safety, which is promoted by the ratepayer-funded Results Sharing program in conjunction with other recognition programs. (Exhibit 21, p. 23.) We reject the contrary inference that would blame the victim for degraded safety performance.

regulation is in a difficult transitional stage following the breakdown of the wholesale electricity market in 2000 and 2001, and it is important to engage in dialogues such as these in order to ensure that future regulation is informed by the views and expertise of all stakeholders. To a large extent, the matters have either been explicitly or implicitly addressed previously in this decision, or do not warrant discussion here in the interests of brevity. In the following portions of Section 14, we review and comment on SCE's obligation to perform integrated resource planning and related topics, as well as SCE's supplier and workforce diversity programs.

### 14.2. Integrated Resource Planning and Utility-Owned Generation

Referring to an Energy Division briefing paper, Commissioner Wood raised several issues related to SCE's power procurement and integrated utility planning capabilities and responsibilities:[67]

- Does SCE have an adequate organization to plan for and meet future resource procurement and production needs? Describe the staff qualifications and resources necessary for SCE to meet the procurement requirement.
- What procurement options is SCE considering (other than contracts?) What other options should be considered?
- What assumptions is SCE making about building new generation?
- What is SCE's current approach to generation, distribution, transmission, and demand-side planning?

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[67] *Assigned Commissioner's Ruling Establishing Scope, Schedule, and Procedures for Proceeding*, August 8, 2002, pp. 2, 4. The ruling noted that it was not the intent to duplicate litigation in I.01-10-024 (the procurement rulemaking proceeding), but it also noted that "the role of the utility going forward in terms of not merely procurement but also energy production is properly before us in this GRC." (*Id.*, p. 5.)

SCE and other parties submitted prepared testimony in response to these questions. In a supplemental ruling Commissioner Wood posed additional questions about SCE's Integrated Resource Planning (IRP) process, to which SCE and other parties responded with additional testimony.[68]

SCE acknowledges the intent to avoid an overlap between this proceeding and the procurement rulemaking, but it nevertheless believes that there are too many unresolved issues to fully resolve the integrated resource planning issues in this GRC. SCE's responsive testimony on procurement and generation issues is summarized below:

> Policy Considerations
> SCE Senior Vice President John Fielder testified that "[n]ot only must the Commission harmonize decisions rendered in [the procurement rulemaking and this GRC], it must now implement the procurement policy decisions adopted in AB 57 and signed into law by Governor Davis on September 24, 2002. Specific minimum requirements for Renewable Generation Portfolio Standards were also adopted recently in the Legislature and signed into law by the Governor. Compliance with these new laws adds yet another layer of complexity to challenge the implementation of effective Procurement policies for SCE. Finally, the Commission, and Parties to the GRC, should be mindful of the additional institutions that believe they now have a role in the procurement decisions for California despite not even being a Party to this GRC." (Exhibit 69, pp. 4-5.)
>
> Power Supply
> SCE notes that under industry restructuring utilities retained the "default provider" obligation to serve their retail customers, and contends that it is still not clear what procurement and resource

[68] *Assigned Commissioner's Ruling on January 21 Energy Division Briefing Paper Regarding Need for Additional Testimony*, January 22, 2003.

planning obligations the Commission intended utilities to have in the post transition period.

Energy Efficiency
SCE contends that the Commission has not yet clarified the role it expects utilities to play in demand-side programs past 2002, leaving this as another unresolved issue in the overall resource plan mix.

Transmission
Prior to restructuring, utilities planned their transmission investments in coordination with their generation plans. Under restructuring, the Independent System Operator has responsibility for establishing certain transmission reliability and planning criteria, while SCE retains responsibility for formulating its own five-year transmission plan using the ISO's criteria.

Other Procurement Related Issues
SCE notes that the Commission has stated that the procurement rulemaking would be the main venue for establishing policies regarding generation supply and resource procurement and integrated planning. SCE maintains that other important public policy issues remain that need to be resolved to enable it to proceed with resource planning and procurement, including protocols for implementing AB 57, issues related to the administration of DWR's long-term contracts, resource adequacy policies of the ISO and FERC, the future role and activities of the California Power Authority, and public policies for funding renewable projects.

Organizations Needed For Procurement And Production
SCE determined that a generic generation organization would be needed if it were to return to development of new generation resources. SCE believes that it would need economies of scale to optimize its staffing, a steady state construction of new plants, and time to staff all of the positions necessary to build and operate new generation. In order to return to generation development, SCE assumes it would need the following: (1) Project Management Organization (60 employees); (2) Operations and Maintenance Staff (60 employees); and (3) Infrastructure (e.g., warehousing and training; 8-15 employees). SCE believes that since it takes a few years to construct a new generation facility, the Commission should address this issue as part of a long-term energy procurement

proceeding or in SCE's test year 2006 General Rate Case, not as part of this proceeding to determine test year 2003 base rates.

IRP Organization

To carry out the task of integrated resource planning in response to the procurement rulemaking, SCE planned to recruit a small staff in 2003 and rely significantly on consultants until sufficient staff is assembled and trained. SCE believes that staffing will ultimately consist of about 16 people, largely with backgrounds in economics and other analytical disciplines, with an estimated budget of $2.6 million.[69] Eventually, SCE will be able to develop multiple scenarios to evaluate tradeoffs of different resources and reliance on different strategies and policies, such as tradeoffs between transmission and local generation options and buy-versus-build decisions. If SCE chooses to pursue substantial generation and transmission projects, this organization could potentially increase by four FTEs. SCE states that if regulators require additional analysis, prescriptive data requirements, or analysis comparable to the Electricity Report/Biennial Resource Plan Update processes, this organization would require a substantial increase in resources. SCE notes that FERC Standards of Conduct (18 CFR § 37.4) require independence between any transmission planning entity and any wholesale marketing entity within the utility. For example, SCE states, relying on ES&M personnel for developing a resource plan would violate the FERC Standards of Conduct. SCE also notes that existing staff is not available to perform these functions.

IRP Process

SCE maintains that the Commission should first establish priorities with respect to the objectives of cost, reliability, and environmental quality, but that these priorities should be broad objectives and preferences rather than prescriptive requirements. SCE states that after the Commission's objectives and preferences have been developed, SCE will undertake analysis and a review of resource options that meet the Commission's criteria. The Commission

[69] The estimated $2.6 million is not included in SCE's 2003 GRC estimates.

would then review the utility's plans and analysis against the policy direction that was provided. SCE states that it is committed to providing rigorous, thorough analysis to describe the benefits and consequences of choosing different resource strategies. For SCE, the "integrating" forum for integrated resource planning takes place in the newly formed Resource Planning Committee, which includes directors and vice presidents from each of the major resource areas in the company. The objective of the committee is to set priorities and make decisions regarding resource choices and long-term investment allocation. It plays an integral part in the development of all integrated resource plans. The integrated plan will provide input to SCE's long-term capital budgeting in addition to developing a long-term fuel and purchased power budget. SCE's current capital budgeting process tends to be short term (five years) and detailed; the integrated plan will provide the benefit of an extended forecast (ten years).

New Utility-Owned Generation

SCE filed comments in the procurement rulemaking taking the position that the Commission should preserve the option of filling customer resource needs through new utility-owned generation to the extent it is in the interests of both customers and shareholders, and that remains SCE's position in this GRC. SCE notes that neither utilities nor the financial community know what California's electric utility industry structure is likely to be ten years from now, nor do they know which customers will be responsible for the recovery of utility-owned generation investment. This makes the risk of future stranded generation investment much greater than that for transmission and distribution investments, according to SCE. SCE contends that both the utility and the investment community must believe that SCE will have a reasonable opportunity to recover its costs and earn a fair rate of return on its generation investment before they would be willing to invest in new utility-owned generation. SCE contends that the utility and the Commission must agree to a framework for fair cost recovery before construction of any new utility-owned generation can occur.

TURN presented an historical analysis of generation procurement policy and IRP and concluded that a model based upon utility ownership of generation creates incentives that can conflict with the goal of optimizing demand-side management (DSM) and renewable resources. TURN recommends that a new integrated resource planning process be instituted, with the planning function assigned to a responsible and capable government agency. TURN believes that the utility should retain the generation procurement function, that utility ownership of power plants should only be pursued as a last resort, and that independent agencies should have responsibility for DSM delivery. Under this model, TURN sees only a limited role for the utility's IRP function, i.e., that of providing inputs to the IRP regulator. TURN believes that if utilities are allowed to build generation, then an independent agency must be assigned to administer DSM and demand-responsiveness programs, and resource planning must largely be done by the Commission. TURN generally agrees with SCE that several important policy decisions, especially the future of direct access, must be resolved before the utility could resume a role in the construction of generation.

Generally concurring with TURN's analysis regarding inherent conflicts of interest, particularly the conflict between the utility preference for capital-intensive investments on one hand and planning and energy-efficiency functions on the other, Aglet does not believe that SCE should resume a primary resource planning function. Aglet believes that primary responsibility for resource planning should be assigned to one or more state agencies.

NRDC recommends that the Commission continue and strengthen its current direction to return utilities to a strong portfolio management role with strong regulatory oversight and policy direction from the Commission. NRDC agrees with TURN that there is a real need for IRP, and that IRP is too important to be left to the utilities without significant and active Commission oversight. NRDC does not, however, agree with TURN's position that responsibility for resource portfolio planning and management should not rest with utilities. NRDC believes that under state law, utilities bear the responsibility for portfolio planning and management, and that the Commission should maintain a strong oversight role. NRDC believes that the conflicts of interest that concern TURN would be problematic under traditional regulation, but are adequately addressed by AB 29X, the National Energy Policy Act of 1992, and AB 57.

CUE contends that utility ownership of generating capacity has several benefits. CUE believes that it can assure that generation will be available to serve customers because utilities have an obligation to serve. CUE points out that as net buyers, utilities have no incentive to withhold generation resources to increase prices or to schedule maintenance during periods of high market prices. CUE also believes that utility ownership of generation would reduce overall reserve margin requirements and facilitate the integrated planning of generation and transmission additions.

***Discussion***

SCE has shown that, at least when it submitted its supplemental testimony in late 2002 and early 2003, there remained considerable policy uncertainty affecting its organizational, strategic, and investment choices in the areas of procurement, generation, and resource planning. Moreover, this uncertainty cannot be adequately addressed in this GRC decision. Accordingly, at this time our interest is in ensuring that SCE is positioned to respond adequately and timely in the medium and long term to evolving policy determinations.

Based on SCE's showing in response to Commissioner Wood's probing, we are confident that, to date, SCE has been taking reasonable steps to so position itself. Earlier this year, in the procurement proceeding, the Commission stated its expectations for IRP and encouraged the utilities to begin designing and creating the internal processes necessary to support IRP. (D.01-04-050, pp. 96-97.) SCE will clearly need IRP capabilities, and its plans to develop a fairly small organization with IRP capabilities and to institute oversight and coordination by the Resource Planning Committee strike us as constructive and reasonably conservative in light of current uncertainties.

With respect to the possibility of developing utility-constructed and utility-owned power plants, we believe that it is not timely to make policy pronouncements here beyond those made in D.01-04-050. As we stated there (at p. 63), we will consider utility-owned and/or utility-built proposals on a case-by-case basis. We note, as CUE has, that there may be significant benefits to such a policy. Thus, at least for now, we preserve the option of filling customer resource needs through new utility-owned generation to the extent it is in the interests of both customers and shareholders. We recognize SCE's determination that additional Commission guidance is required before SCE or the investment community can give a green light to such investments, even as we reserve the right to determine in other forums the nature of that guidance. We concur with SCE that if and when the Commission considers the desirability of having utilities construct new generation subject to cost-of-service ratemaking, there will be a need to consider an explicit framework governing risk allocation, rate of return, cost recovery, length of the arrangement, and disposition of any residual value. We will not at this time otherwise address ORA's position that we should not allow utilities to recover the costs associated with constructing and operating generating facilities directly through base rates.

### 14.3. Supplier Diversity

In response to Commissioner Wood's request for testimony on SCE's women, minority, and disabled veteran business enterprises (WMDVBE) program, SCE submitted testimony describing its supplier diversity program, its compliance with GO 156, and its related outreach program. Greenlining and DVBEA also addressed SCE's supplier diversity program.

SCE states that it is committed to providing opportunities for WMDVBEs to participate in its purchasing and contracting activities on a competitive bidding basis. SCE states that its supplier diversity program is considered among the leading efforts of its kind, and notes that it has exceeded and continues to exceed the Commission's good-faith goal of procuring at least 25% of its major products and services from WMDVBEs. During 1996–2000, SCE also met or exceeded its internal goals in every year except for 1996 and 1998, and even in those years it fell short of the internal company goals by less than one-half of one percentage point.

SCE believes that its supplier diversity outreach program has contributed to its ability to exceed the Commission's overall WMDVBE goal. The outreach program includes participation in many organizations that offer support to WMDVBEs. This participation takes the form of program planning, financial support, in-kind donations, technical assistant, and direct participation. The outreach program also includes programs such a series of SCE-hosted workshops called "Next Generation" to empower WMDVBEs with the expertise and best practices planning strategies to improve their businesses. SCE is also a founder and sponsor of the "California Partnership on Diversity," a partnership of nearly a dozen of California's top companies developed to encourage and promote the business and economic benefits of embracing diversity, including in the areas of equal opportunity and human resources and the procurement of goods and services from minority and women-owned business enterprises.

With respect to DVBEs, SCE has taken several steps to inform suppliers of opportunities to participate in SCE's supplier diversity program. SCE regularly advertises in "Challenge News," a trade paper for DVBEs, and it sponsors and participates in DVBE community-related outreach activities such as the DVBEA's annual awards banquet and trade show. In 1999, SCE attempted to increase DVBE participation by contracting with a DVBE management consultant to develop and implement a survey of nearly 500 DVBE firms in California. This was done to determine their capabilities and potential to provide goods and services to SCE. It resulted in a "short list" of 80 firms most likely to provide products and services to SCE or its prime contractors. During the GRC hearings SCE stated that it would add to its suppler diversity staff an employee who will act as a single point of contact for the DVBE community and who will concentrate on outreach efforts to DVBEs and American Indians. SCE also plans to schedule meetings with other utilities to discuss their outreach efforts, maintain ongoing communications with DVBEs and meet with DVBE representatives on a monthly basis, survey the DVBE community to update database profiles, schedule meetings with SCE business contacts and DVBE representatives, and reinitiate the Partners in Diversity Program.

Exclusions from WMDVBE goals are permitted under GO 156. Greenlining asks the Commission to encourage SCE to "work toward eliminating unnecessary and excessive exclusions in minority procurement reporting." (Greenlining opening brief, p. 1.) Greenlining witness Gamboa believes that SCE's WMDVBE procurement program is excellent compared to the "abysmally low" national average of 3% for minorities, but that there is nevertheless room for substantial improvement in SCE's program. He finds SCE's use of GO 156 exclusions troublesome, and questions SCE's apparent assumption that there are no potential minority suppliers in a wide range of fields, including passenger carrier and charter services, tool and equipment rentals, and health care consulting. He also indicates concern that SCE has seemingly accepted a decrease in Minority Business Enterprise procurement from 2000 to 2001 among all major ethnic groups, and that SCE appears to have made little effort to change these circumstances.[70] Gamboa believes that the Commission should set goals for SCE in this GRC for eliminating the use of exclusions and increasing WMDVBE procurement. Greenlining believes that SCE should be encouraged to hold a consortium of minority business enterprises to discuss areas where improvements can be achieved with respect to exclusions.

DVBEA's purposes are to "assist, enable, support, and empower disabled veterans in establishing and maintaining viable business enterprises, to defend the rights of disabled veterans in business granted by the legislature of the State of California, and to eliminate prejudice and discrimination against disabled veterans in business, both public and private." Concerned that SCE has not made significant progress toward meeting obligations to DVBEs, DVBEA requests that SCE be directed to quickly meet or exceed the 1.5% DVBE participation goal set by GO 156.[71] DVBEA's specific recommendation is that

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[70] In its opening brief, at p. 9, Greenlining cites to a 2003 Greenlining report on the status of minority procurement by regulated utilities and testimony of Greenlining witness Gelly Borromeo. However, neither the status report nor the Borromeo testimony cited by Greenlining is in this GRC record. Inasmuch as the cited material is not record evidence, we accord it no weight.

[71] As computed by DVBEA, SCE's reported DVBE expenditures as a percentage of its contracting expenditures were 0.12%, 0.21%, 0.17%, and 0.09% in the years 1996 through 1999 respectively. (Exhibit 277, p. 3.) As computed by SCE, DVBE participation rates were 0.12%, 0.20%, 0.20%, 0.10%, 0.20%, and 0.10% in the years 1996 through 2001 respectively. (Exhibit 73, p. 99.)

SCE file, as a supplement to the Annual Plan described in Section 10 of GO 156, a special, detailed report on the DVBE component of its diversity program. DVBEA also requests that GO 156 be amended to provide for monetary penalties directed at improving DVBE participation over a reasonable period of time.

***Discussion***

As a preliminary matter, we note that a utility's failure to meet one or more of the contracting participation goals in GO 156 does not necessarily mean that the utility is out of compliance with the GO. There are no associated penalties for failing to meet the goals or rewards for exceeding the goals. As another preliminary matter, we note that this is not an appropriate proceeding for considering or adopting modifications to GO 156, which is not limited in its application to SCE. This includes proposals to prohibit SCE from applying exclusions that are currently permitted under GO 156 as well as proposals to subject SCE to higher goals than those set by GO 156.[72] However, while modifications to GO 156 are not at issue here, that would not necessarily preclude our requiring supplemental reporting by SCE if we were to determine that is appropriate.

In this GRC, we consider whether SCE is making sufficient efforts to achieve applicable GO 156 goals, and whether any additional measures are required of SCE at this time. As summarized above, SCE has shown that it conducts a comprehensive outreach program in its efforts to achieve GO 156 participation goals. Until and unless we know more about the attainability of the

[72] Modifications to GO 156 addressing exclusions are being considered in R.03-02-035.

goals and the reasonableness of exclusions, we cannot say with certainty whether SCE should be required to undertake more outreach efforts or take other steps to achieve supplier diversity goals. However, nothing in the record of this GRC indicates that SCE's efforts to achieve GO 156 participation goals are in any way inadequate, and we therefore decline to order SCE to organize a consortium for the WMDVBE community. With respect to DVBEs specifically, our sense is that SCE has enhanced its outreach efforts during the course of the proceeding, and that additional annual reporting requirements such as those proposed by DVBEA are not required at this time. We will, however, expect full reporting on the supplier diversity program, including but not limited to the DVBE component, in SCE's next GRC filing.

### 14.4. Workforce Diversity

Pursuant to rulings by Commissioner Wood on April 8 and May 5, 2003, SCE submitted testimony on the diversity of its workforce as well as its plans regarding workforce diversity. SCE believes that workforce diversity helps drive success, and it notes that it has a longstanding commitment to workforce diversity and equal employment opportunity. SCE continually evaluates its employment practices and programs to have the workforce reflect the pool of qualified women and minorities in the labor market. SCE also has programs in place to ensure that once employed by SCE, all employees have the opportunity to develop their talents and skills. Since the 1970s, SCE has had a department overseeing equal employment opportunity and diversity issues, and since the mid 1980s the department has been a stand-alone organization. For the last seven years, the Vice President of Equal Opportunity, reporting directly to the President of SCE, has headed the department. SCE believes that this allows for diversity issues to be communicated directly to senior management.

SCE's workforce has become increasingly diverse since 1990. In March 2003, minorities made up 44% of SCE's workforce, compared to 32% in 1990; and minorities plus non-minority females made up 57% of the workforce, compared to 46% in 1990. SCE presented data showing that this overall increase in diversity extends, for the most part, to the various job categories studied (executive, managers, technicians, administrative, jobs requiring certification, and bargaining unit employees) and to the groups analyzed for diversity (women, total minorities, African American, Asian, Native American, Latino).[73]

There were exceptions, however. Between 1990 and 2002, female representation in the full and part-time workforce increased significantly in the executive and managerial ranks (from 5.0% to 21.0% and 15.8% to 25.8% respectively), but it changed relatively little for technicians (from 10.7% to 11.5%), administrative (from 75.7% to 74.4%), jobs requiring certification (from 13.0% to 13.3%), and bargaining unit personnel (from 11.2% to 10.2%). Overall, minority representation increased for all job categories, most notably in the executive category, where each of the minority categories saw increased representation. However, in certain areas minority participation actually declined, if only slightly. African American representation in jobs requiring certification declined from 3.9% to 3.8%, and in bargaining unit jobs it declined from 8.3% to 7.8%.

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73 The data is presented in Table I-1 of Exhibit 413. SCE presented data for job categories with a total of 8,281 employees in 2002 (105 executives, 621 managers, 1,136 technicians, 1,146 administrative, 346 jobs requiring certification, and 4,927 bargaining unit jobs), or approximately two-thirds of its total workforce. The data for 1990 covered a total of 13,319 employees (40 executives, 557 managers, 2,343 technicians, 2,584 administrative, 254 jobs requiring certification, and 7,541 bargaining unit jobs)

Native American representation in technician jobs declined from 1.4% to 0.8% and for bargaining unit jobs it declined from 1.4% to 1.2%.

In 2002, 49.3% of SCE's hires were minorities and the combined minority/non-minority women hiring rate was 65.3%. To ensure diversity in the candidate base, SCE works with organizations that are focused on social issues concerning minorities and women, attends targeted job fairs, engages on college campuses known for diversity of their students, and tracks the makeup of the workforce. SCE developed a form, provided to recruiters, that identifies when a position open to external recruiting is underutilized, i.e., the diversity of the employee base in that position is less than the representation in the qualified labor market. SCE states that, in addition to recruiting, it maintains a focus on leadership development and mentoring. SCE also provides mandatory diversity training for all employees, including officers, to ensure all employees understand SCE's commitment to valuing differences in culture, gender, thinking style, race/color, marital status, work experience, medical condition, pregnancy, veteran status, age, religion, language, physical or mental disability, sexual orientation, and national origin.

***Discussion***

Review of the utility's employment practices is clearly within the purview of a general rate case. A utility that fails to achieve workforce diversity denies itself and ultimately its customers significant advantages. These include making the utility an attractive employer with a more capable and motivated workforce, as well as compliance with applicable state and federal laws. As an SCE brochure for supervisors and managers states:

> In today's economy, workforce diversity is a critical business imperative. Fostering a truly inclusive organization – one that

> makes full use of the contributions of all employees – goes beyond being the "right thing to do." (Exhibit 413, p. Attachment D.)

Between 1990 and 2002 SCE made significant progress in increasing the diversity of its overall workforce. There are exceptions, such as the decline in African American participation percentage in the bargaining unit category. Also, as Greenlining notes, Latino representation is low among among SCE's top 500 and top 1,000 employees. Still, we are satisfied that SCE has adopted and embraced policies and practices that will continue to address areas of under-representation throughout its workforce. We recognize that industry restructuring and the associated reorganization of SCE, including the divestiture of generation plants, may have impacted the company's efforts to address workforce diversity.

SCE should provide an update on its diversity program in its next GRC filing. Among other things, SCE should update the information presented in its supplemental testimony on workforce diversity (Exhibit 413, Table I-1). The data presented therein should be refined to include, for administrative positions, a breakdown of women and minority representation among supervisory and non-supervisory personnel. Also, SCE should address diversity for the approximately 4,000 employees not included in Table I-1.

## 15. Disposition of Memorandum Account

Under the rate case plan as traditionally applied, the Commission endeavors to adopt the test year revenue requirement in a GRC prior to the start of the test year. This was not possible in this GRC for a variety of reasons. SCE initiated this GRC approximately five months after the date when it would have been possible to have first-of-year implementation under the processing intervals specified in the rate case plan.[74] In addition, it became necessary to provide additional time to enable full participation by ORA in accordance with Section 309.5, and other processing delays have been encountered during the course of this GRC.

Taking the position that a Commission decision would have been issued on May 22, 2003 based on the application filing date and the rate case plan schedule, SCE filed a motion to establish a memorandum account to track the requested revenue requirement between May 22, 2003 and the date of a final decision in Phase 1 of this GRC proceeding. D.93-05-076 dated May 22, 2003 granted SCE's motion in part. While it approved the memorandum account, it dismissed without prejudice those provisions of the motion that pertained to the disposition of the memorandum account balance and associated rate recovery. Pursuant to this authorization, SCE filed Advice Letter 1710-E to establish the GRC Revenue Requirement Memorandum Account (GRC RRMA).

In order to develop a complete and current record regarding disposition of the memorandum account authorized by D.93-05-076, in a June 10, 2003 ruling the ALJ directed SCE to file a motion setting forth its proposal for such disposition. The ruling also directed SCE to address any implementation issues, including rate volatility, that might be associated with a Commission decision which was then pending in A.03-01-019.[75] SCE timely filed the motion regarding

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[74] For this reason, SCE requested in its GRC application that the authorized revenue requirement become effective as soon as possible in 2003, and it proposed a schedule that would have resulted in issuance of a Commission decision on May 22, 2003.

[75] In that proceeding, SCE sought to lower and adjust retail rates upon recovery of the Procurement Related Obligations Account (PROACT). On July 10, 2003, the Commission resolved A.03-01-019 by D.03-07-029 (the PROACT decision), which

*Footnote continued on next page*

disposition of the memorandum account on July 18, 2003. No responses to SCE's motion were filed.

Under SCE's proposal, the GRC RRMA tracks and determines for the period between May 22, 2003 and the date of the final Phase 1 GRC decision the difference between (1) the GRC revenue requirement ultimately approved by the Commission and (2) amounts actually recovered by SCE through various approved ratemaking mechanisms prior to a final 2003 GRC decision. Rate levels will be adjusted to reflect the adopted GRC revenue requirement on a prospective basis and will also be adjusted temporarily to amortize the GRC RRMA balance. To accomplish this, SCE proposes that on the effective date of this GRC Phase 1 decision, the GRC RRMA balance shall be transferred to the Base Revenue Requirement Balancing Account (BRRBA) and differences between authorized GRC revenue requirements and recorded GRC-related revenues shall be recorded in the BRRBA.

SCE believes that various anticipated rate changes, including those to be implemented pursuant to this decision as well as rate changes associated with the Department of Water Resources revenue requirement, be consolidated to avoid imposing several rate changes on customers within a relatively short span of time. SCE proposes that as part of the consolidated rate change, the applicable authorized Phase 1 revenue requirement shall be included in rate levels along

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approved a post-PROACT settlement agreement and lowered SCE's retail electric rates by $1.25 billion. Pursuant to the PROACT decision, PROACT settlement rates will remain in effect for 12 months, with the exception that any revenue requirement changes approved in Phase 1 of this GRC or in other proceedings will be reflected in SCE's rates on a system average percentage change (SAPC) basis until Phase 2 rates are implemented.

with the December 31, 2003 balance in the BRRBA such that the December 31, 2003 BRRBA balance is fully amortized on or around December 31, 2004.

***Discussion***

No party has taken issue with SCE's proposal for disposition of the memorandum account authorized by D.03-05-076 and related rate recovery. The PROACT decision has determined that the revenue requirement adopted today will be implemented by adjusting rates on an SAPC basis. We find that this proposed procedure appropriately balances the interests of the utility and its ratepayers by leaving them essentially indifferent to the effective date of this Phase 1 GRC decision. In addition, it minimizes the confusion that would be associated with frequent rate changes. SCE's motion will therefore be granted as reasonable. The BRRBA will be trued up in SCE's ERRA proceedings.

## 16. Comments on Proposed Decision

The ALJ's proposed decision was issued pursuant to Public Utilities Code Section 311(d). Pursuant to Article 19 of the Rules of Practice and Procedure, parties were permitted to review and comment on the proposed decision.

## 17. Assignment of Proceeding

Carl Wood is the Assigned Commissioner and Mark S. Wetzell is the assigned ALJ in this proceeding.

## Findings of Fact

1. SCE's financial condition has improved significantly since the height of the state's energy crisis and SCE's financial crisis.

2. SCE has not shown that it requires the full amount of its requested base revenue increase to achieve the financial health it requires to provide adequate utility service.

3. The electric rates of California investor-owned utilities, particularly those of SCE, are comparatively high by several standards.

4. SCE's high rates are harmful to ratepayers and to the California economy, and add to the threat of utility bypass.

5. The forecasting principles discussed in D.89-04-060 and D.89-12-057 are generally appropriate for this proceeding.

6. It is reasonable to assume that the capital related costs of SCE's IRP have been included in rates during the term of SCE's PBR mechanism.

7. SCE had an incentive to defer capital expenditures during the latter part of the PBR period.

8. Capital spending budgets are not necessarily carried out as planned, as there is no specific obligation under conventional cost-of-service or incentive ratemaking to spend budgeted amounts during the relevant time period, and in carrying out its SONGS capital spending plans SCE requires flexibility to optimally respond to changing circumstances.

9. A utility's budget-based forecast may be less reliable than a forecast based on historical capital spending data, which reflect not only past spending plans, but also the utility's willingness and ability to carry out those plans.

10. SCE forecast SONGS capital spending of $510 million during the 1996-2003 period for the purpose of establishing the ICIP mechanism, but it actually will have spent just slightly more than a third of the forecast amount.

11. Determining whether it can reasonably be concluded that ratepayers have already paid, in whole or in part, for SONGS capital additions does not represent an after-the-fact reasonableness review precluded by the ICIP mechanism.

12. Ratepayers have already made contributions to the SONGS Used Fuel Storage and Marine Mitigation projects through the ICIP rates.

13. An average of actual expenditures is more reliable than a straight budget-based forecast of SONGS 2 & 3 capital expenditures, but ORA's averaging approach for SONGS capital spending requires correction to account for the effects of inflation.

14. Because it is reasonable to determine that ratepayers have made contributions to the cost of the SONGS Used Fuel Storage project as well as marine mitigation costs, but it is impossible to calculate the precise amount of that contribution, the fairest outcome is to assign equal cost responsibility for remaining costs of the project.

15. Costs for wetlands restoration of 20 acres at San Dieguito do not affect customer rates.

16. It has not been shown that SCE unreasonably, and without cause, deferred the replacement of SONGS off-site sirens and monitors to the GRC test period.

17. Funding for the off-site siren and monitoring replacement project is necessary to providing a seamless transition to the new monitoring system without risking public health and safety.

18. TURN's analysis and recommended disallowances of SCE's increased spending on several small work orders at SONGS, including tools and equipment, computers, office equipment, facilities, and spare parts, is not without merit, but because we are adopting a forecast which relies on the averaging of historical expenditures, which in turn results in disallowances of certain of SCE's proposed expenditures, TURN's recommendation could result in an unfair duplication of disallowances.

19. SCE is ineligible to participate in the Employment Training Program with the return of SONGS 2 & 3 to cost-of-service ratemaking.

20. SCE has not demonstrated that it is appropriate to use Y2K project costs as a proxy for SONGS O&M projects that were deferred as a result of the Y2K project during the period 1998-2000.

21. The SONGS 2 & 3 awards and recognition program provides employees with performance incentives, and includes no dues, donations, or charitable contributions.

22. Because the 1992-1996 SONGS Nuclear Rate Regulation (NRR) expenditures do not include certain "matrixed" personnel costs, an averaging methodology for that period does not capture all of the NRR costs, rendering it less reliable than SCE's Adjustment #38.

23. For the forecast of SONGS Site Projects O&M expenditures, for which expenses can vary from year to year, a three-year average (1998-2000) should produce a more reliable forecast than any single recorded year or a departmental budget.

24. Inclusion of $1.710 million for pre-1999 claims under the Master Insurance Program (MIP) in the SONGS O&M forecast is reasonable because (a) the ICIP proposal adopted by D.96-04-059 included a provision by which SCE could request recovery of certain expenses separately from the ICIP price, including worker and third-party claims; (b) there is no evidence that ICIP prices included all claims begun during the ICIP period; and (c) with respect to earlier claims, there is no basis for characterizing them as stranded costs.

25. SCE had difficulty filling SONGS technician positions in 2001 and 2002, and since mid-2002 it has only been able to hire nuclear trained engineers with signing bonuses and relocation allowances.

26. SCE recorded approximately $1 million in additional costs in 2002 to attract, hire, and train qualified replacements for nuclear trained personnel at

SONGS, which corroborates the need for a test year labor scarcity adjustment of $1 million.

27. As a result of the September 11 terrorist attacks and subsequent NRC directives, added security costs have been created for SONGS 2 & 3 in 2003 that did not exist during the 1996-2000 historical period, and the SONGS 2 & 3 co-owners are at present solely responsible for these increased costs.

28. SCE's Adjustment #45 for $5.650 million is a reasonable means of recognizing known added security costs that SCE must incur at SONGS.

29. Programmatic changes affecting expenses recorded in the SONGS Maintenance/FERC Account 524 pairing were reflected in the 1998-2000 period, and use of a three-year average (1998-2000) for the labor forecast for the pairing is more reasonable than use of the last recorded year.

30. The SONGS Maintenance/FERC Accounts 530, 531, and 532 functional group pairings are linked because of how activities were reported; therefore, a consistent methodology should be used for the labor component forecast of all three accounts, and five-year averaging is appropriate because of the cyclical nature of the underlying activities and related expenditures.

31. For the SONGS Nuclear Support/FERC Account 524 pairing, severance transactions affected 1995 and 1996 only, no cause exists to exclude costs for 1997, and four-year averaging method is therefore reasonable.

32. For the SONGS Nuclear Support/FERC Account 528 pairing, there is no basis for assuming that no expenses except for MIP costs will occur in the test year; therefore, use of a three-year average of recorded/adjusted data that excludes 1996 and 1997 is reasonable.

33. For SONGS Nuclear Support/FERC Account 532, use of a three-year average (1998-2000) rather than a five-year average for non-labor to reflect a 1998 accounting change is not justified.

34. For both SONGS Operations/FERC Account 524 and Nuclear Support/FERC Account 529, five-year averages rather than the last recorded year and four-year averages, respectively, are likely to yield more reliable forecasts.

35. For SONGS Maintenance/FERC Account 528, use of the last recorded year is appropriate because (a) for labor, SCE gained efficiencies through programmatic enhancements and (b) for non-labor, only the year 2000 fully reflects cost reductions associated with inventory reductions.

36. For the SONGS Radchemical Control/FERC Account 523 pairing, use of the last recorded year for both labor and non-labor is necessary to reflect cost shifts from Account 520.

37. In order to remove all SONGS refueling and maintenance outage O&M costs from the base O&M forecast, a total of $2.557 million in outage costs should be removed from the affected functional group/FERC Account pairings underlying the base O&M forecast.

38. SCE's Adjustment #36, updated to reflect total SONGS-related NRC license fees of $6.138 million (2000 dollars) as set forth in the Federal Register of April 3, 2003, is reasonable.

39. Inclusion of refueling and maintenance outage-related expenses in the base O&M forecast for SONGS could lead to a less reliable forecast compared to a mechanism that uses more reliable annual forecasts of the number of outages in the following year.

40. SCE's proposal to add to the SONGS 2 & 3 refueling and maintenance outage cost estimate the $2.557 million in outage related O&M expenses removed from the base O&M forecast lacks evidentiary support.

41. Due to a fire and forced outage in SONGS Unit 3 in 2001, the unit refueling and maintenance outages are now nine months apart, and mobilization costs are incurred for each outage.

42. A per unit per outage adjustment of $1.5 million that reflects the need for SCE to mobilize its outage forces is reasonable.

43. SCE's estimates for SONGS Unit 1 direct shutdown O&M expenses of $3.864 million for 2003 and its estimated allocation of SONGS common costs to SONGS Unit 1 shutdown O&M of $3.310 million are reasonable.

44. To ensure consistent treatment of SONGS expenditures and to avoid duplicate litigation, the Commission has addressed SONGS-related expenses that SCE bills to SDG&E in SCE's GRCs.

45. The framework underlying SDG&E's proposals for recovery of its share of SONGS 2 & 3 capital additions, base O&M, and refueling outage O&M, and SONGS 1 shutdown O&M, is reasonable and consistent with prior decisions for addressing SDG&E's SONGS costs in SCE's GRCs.

46. The amounts requested by SDG&E must be adjusted to reflect the capital and O&M costs for SONGS 2 & 3 as well as the amortization period adopted in this decision.

47. SCE's project-specific forecast of capital expenditures for Palo Verde is reasonable.

48. Palo Verde O&M costs have been consistently declining, and the budget-based forecast of $39.517 million in Exhibit 327 shows continued declines that are not reflected in historical costs.

49. Most of SCE's planned investments for Mohave are important for reliable operations through 2005.

50. The Mohave Cooling Tower 1EE investment was needed for safety as well as reliability purposes.

51. The level of SCE's planned capital spending at Mohave is generally consistent with expenditures of the 1996-2000 period.

52. SCE's O&M expense forecast of $30.633 million for Mohave is consistent with the adjusted average O&M expenses for years prior to 1999.

53. Due largely to the then-pending sale of Mohave, SCE spent less on maintenance in 1999 and 2000 than it would have in those years if it had not been planning to divest the plant, and this reduced level of spending is not likely to recur in the test period.

54. Capital spending at Four Corners is heavily influenced by plant overhaul schedules, and historical expenditures vary considerably from year to year.

55. Over 82% of the capital expenditures planned for Four Corners are focused on production reliability.

56. Since major outage overhauls are not planned for Four Corners in 2003, it would not be reasonable to include the costs of such overhauls in the Four Corners O&M forecast for 2003.

57. Using project-specific analysis, SCE forecasts hydro system capital expenditures of $17.691 million in 2002 and $15.121 million in 2003, or a total of $32.812 million.

58. ORA recommends an average of historical expenditures as the basis for the hydro capital expenditures forecast, but when appropriate corrections are made to ORA's forecast, the result is a reduction of $942,000 from SCE's project-

based forecast for 2002 and an increase of $1.888 million from SCE's forecast for 2003.

59. SCE's project-based forecast of hydro capital spending of $32.812 million is consistent with a properly determined averaging approach.

60. With the exception of the Florence Dam buttress repairs, which were suspended in the 1990's while seismic retrofit work was anticipated, there is no basis for concluding that activities funded by hydro O&M spending have taken on the degree of added importance during the GRC test period reflected in SCE's hydro O&M forecast.

61. With the exception of Florence Dam buttress repairs, for which we will add $845,000, ORA's hydro O&M forecast of $25.661 million gives appropriate weight to past spending and needed projects.

62. SCE's O&M forecast and its adjusted capital forecast for Other Generation, are uncontested.

63. The Commission's objectives in D.97-09-048, in which standards for evaluating generation capital additions were determined pursuant to Section 367, were a level playing field in the generation market and encouraging cost-effective investments that would maintain reliability.

64. With the enactment of ABX1-6, Section 377 now requires that utilities retain their generation facilities at least through 2005, subject to Commission regulation, and that the Commission act to ensure that these generation facilities remain dedicated to service for the benefit of California ratepayers.

65. In D.02-11-026, the Commission stated that the requirements of Section 367 are no longer applicable to the extent that those requirements conflict with those of ABX1-6.

66. With the enactment of ABX1-6, utilities do not have the opportunity they previously had to recoup through divestiture capital investments that are not funded by ratepayers.

67. With the enactment of ABX1-6, the Commission must provide for the utility's reasonable opportunity to recover the appropriate costs of maintaining and operating retained generating facilities through 2005.

68. SCE's 1997-98 non-nuclear generation capital additions are not "uneconomic" costs within the meaning of Section 367, and Section 367(a) therefore does not prohibit their recovery in this GRC.

69. The payback periods advocated by ORA and TURN for purposes of evaluating the cost effectiveness of 1997 and 1998 non-nuclear generation capital additions are associated with the standards of Section 367 and D.97-09-048, and the transition to a more competitive generation market.

70. The appropriate way to measure the cost-effectiveness of SCE's 1997-98 non-nuclear generation capital additions is to review the benefits over the remaining life of the generating station or the life of the capital addition, whichever is shorter.

71. Since we are not enforcing the heat rate standard adopted in D.97-09-048, it is not appropriate to adopt recommended disallowances that are based upon the asserted failure of a project to meet the standard.

72. Each of the 1997-98 hydro projects identified by ORA for which actual project expenditures exceeded SCE's budget by more than 10% is cost-effective.

73. During the period of time between the opening of a work order and its closure, there could be many capital closings to plant in service; therefore, the fact that certain work orders associated with the 1997-98 projects at issue in this GRC were closed after March 31, 1998 does not demonstrate that SCE has

impermissibly sought capital cost recovery for projects outside the scope of this proceeding.

74. Because the benefit of a casualty loss goes to ratepayers, the benefit does not provide for recovery of the cost to replace the asset.

75. While SCE's T&D reliability is generally high and customer satisfaction is rising moderately, it is at least theoretically possible to create an overly reliable T&D system, adding unnecessarily to ratepayer costs.

76. The 1983 Deteriorated Pole Report recommended intrusive inspection of all poles older than 20 years on a 15-year cycle, a goal adopted by SCE and proposed and accepted in SCE's 1985 GRC.

77. SCE's T&D O&M costs have included a pole treatment and inspection component in every GRC beginning with the test year 1983 GRC, and even where not explicitly addressed in GRC decisions, it is possible to make an estimate of the number of pole inspections connected to the funding received.

78. SCE's testimony in the 1995 GRC stated SCE would schedule 113,000 pole inspections yearly until the remaining inventory of over one million uninspected poles was inspected and treated, starting in 1995 and continuing through 2003.

79. Even though SCE's 1995 GRC was succeeded by a PBR mechanism, it is reasonable to conclude that the level of pole inspections included in the 1995 GRC continued throughout the PBR period.

80. The 77,800 annual pole inspections forecast in the 1985 GRC and the 113,000 annual inspections forecast in the 1995 GRC included visual-only inspections as well as intrusive inspections.

81. Because only 20% of SCE's poles were in service less than 20 years, it is reasonable to estimate that 80% of the poles in SCE's inventory were greater than

20 years old and would therefore have qualified for intrusive inspections under SCE's criteria.

82. An estimated 1,256,154 intrusive pole inspections that included a treatment to extend the pole life were funded through ratemaking authorizations in GRCs over the past 20 years, while SCE completed 961,982 intrusive inspections, or 77% of the funded level.

83. Nothing in the adoption of GO 165 suggested that SCE should slow the pace of intrusive pole inspections that was set in the 1995 GRC and continued through the PBR mechanism.

84. With the exception of Ordering Paragraph 15 of D.96-01-011 in SCE's 1995 GRC, SCE was not under a specific mandate pursuant to a GRC decision over the past 20 years to perform a given number of intrusive pole inspections in a particular time period.

85. SCE estimates that it needs to perform an average of 125,000 intrusive inspections per year through 2006 to meet the requirements of GO 165.

86. Requiring that shareholders fund a portion of the required number of intrusive pole inspections in this GRC cycle gives effect to the principle that ratepayers should not be required to pay twice for the same authorized expense.

87. Even if it was appropriate for SCE exercise its spending discretion in order to address emergent issues in any one year, it is also reasonable and appropriate to hold SCE accountable for completing the intrusive pole inspections that ratepayers paid for over a longer period.

88. With the issuance of D.96-01-011 in January 1996, SCE was on notice that, for safety reasons, the Commission expected that the funded inspections were to be timely completed.

89. From 1996 to 2002, SCE was funded to perform an estimated 632,800 intrusive inspections, but it actually performed 563,866 such inspections, a shortfall of 68,934 inspections.

90. Because intrusive pole inspections were delayed, SCE now has to replace poles that would have remained in service longer had they received timely fungicide treatment.

91. Each missed intrusive inspection translates into a current pole replacement cost of approximately $330 after 20 years, or a net present value of $59 at 9%.

92. Reports on SCE's intrusive pole inspections that are in addition to GO 165 requirements and SCE's showing in its next general rate case regarding the pole inspection program are not necessary.

93. SCE was able to complete and record $723 million in actual T&D plant additions in 2002, exceeding the GRC forecast by $5 million.

94. T&D capital expenditures during 2001-2002 were $2 million above the amount that SCE forecast in the GRC application.

95. Wood pole replacement cost data used to show that recorded costs were 16.4% below SCE's forecast for 2002 are not demonstrably based on cost figures equivalent to those in the forecast.

96. Depending on the method used to escalate wood pole replacement costs underlying the 1995 GRC, the equivalent year 2000 unit cost estimates (excluding additional work items) range from $6,511 to $7,155.

97. It cannot be concluded from this record that SCE's rural-urban distribution of pole installations relative to that of PG&E explains the difference in the two companies' unit pole replacement costs.

98. It is reasonable to reduce SCE's authorized wood pole replacement cost by $526 per unit to conform to PG&E's forecast cost.

99. Use of 2001 FERC account data to forecast T&D O&M expenses is inconsistent with the intent of the Commission's Rate Case Plan.

100. Recorded FERC Form 1 data for 2001 are unadjusted, and therefore are not consistent with adjusted data for the 1996 to 2000 base record period in this GRC.

101. The conditions associated with SCE's financial crisis in 2001 render that year's recorded data less reliable for forecasting test year expenses.

102. For FERC Account 582 (Distribution Station Expense), the fact that vacant operator positions must be filled and retention bonuses paid does not justify rejection of a five-year average methodology.

103. SCE has fulfilled the relevant requirements of Resolutions E-3712, E-3771, and E-3772, and has demonstrated that certain subtransmission expenses discussed therein were properly included in PBR revenue requirements.

104. No basis exists in this GRC for a ratemaking disallowance related to the reasonableness of SCE's T&D capital additions associated with line and distribution extensions.

105. SCE may need to modify its record keeping so that it is able to keep track of line and service extension data in a manner that would allow calculation of total line extension job costs recorded to rate base, total estimated costs, and total allowances for the same work orders.

106. Our intent is to include in the adopted GRC revenue requirement the discretionary funding approved in the LEV proceeding.

107. ET program expenses that relate to mass transportation are not part of the LEV proceeding.

108. SCE has not adequately studied whether the purchase of propane, natural gas, or other non-electric AFVs permitted under EPAct would cause significant costs for refueling infrastructure.

109. Although D.95-11-035 found that the use of electric vehicles by electric utilities to meet EPAct requirements was sensible and appropriate, it did not prescribe exclusive use of electric vehicles.

110. The fact that only 31 vehicles were available for purchase in 2000 should have alerted SCE that its commitment to the exclusive use of electric vehicles required reevaluation.

111. To forecast Accounts 901 and 903.200 (Customer Service Operations), three-year averages are reasonable to avoid year-to-year variations and/or anomalies in the base year recorded costs.

112. A five-year average is appropriate for estimating the uncollectible factor because it includes the effects of the POSID process for assessing the creditworthiness of new service applicants, and unemployment and poverty rates may not be reliable predictors of SCE's uncollectible factor.

113. With the adoption of an LPC, it is reasonable to include an adder of 0.005% with the five-year average uncollectible factor of 0.319% for a total uncollectible factor of 0.324%.

114. With respect to the level of service provided to customers who use APAs and LBOs to pay their bills, SCE is performing satisfactorily overall.

115. Customers now have the ability to use the Internet to interact with SCE, and to an extent do so instead of using other forms of communication.

116. SCE's direct access related customer expenses are essentially fixed if the number of direct access customers remains within the 30,000 to 70,000 range.

117. Insufficient reason has been shown why direct access related customer expenses for the test year would be higher than the 2002 level of $3.690 million.

118. PGC funding will not be eliminated in the near future, and it is available for the technology centers or the pump test program.

119. Because forecasting enrollment levels in the Air Conditioner Cycling Program is particularly difficult at this time, adoption of SCE's forecast subject to a one-way balancing account is reasonable.

120. Balancing account treatment is not necessary for all SCE's load-control programs as their administrative costs are relatively stable.

121. Consistent with the specification of the RIM test in D.95-06-016, the RIM test should measure what happens to total customer bills or rates due to changes in utility revenues and operating costs caused by the E&BD program, and should therefore include generation-related costs and revenues.

122. With the understanding that SCE will make the offer available to all similarly situated customers, we endorse SCE's commitment to provide LA County with billing data through a modified EDI offering.

123. No municipality has taken advantage of SCE's third-party financing program.

124. SCE is willing to work with LA County to better understand the County's borrowing limitations, and to work with the County and participating lenders to determine how the County's needs can be addressed through a third-party lending program.

125. SCE currently provides a bill insert notice to customers describing the impacts of its rate proposals by customer class.

126. The benefits of providing a detailed ratepayer impact analysis on SCE's website may not justify the costs.

127. The Commission's stated conditions in D.96-01-011 for consideration of an LPC have been met.

128. The concern that a residential LPC will impact low-income customers is mitigated by the fact that the impact would not be significant and by SCE's agreement to exempt CARE customers from the application of the LPC.

129. Even though low-income ratepayers and renters move more often and therefore incur the service establishment charge more often than other ratepayers, that does not establish conclusively that low-income ratepayers and renters are unduly impacted by the charge.

130. A $5 per month direct access customer charge would not materially change the economics of direct access transactions, but it would reduce the current subsidy to direct access customers.

131. ORA's proposed schedule of service charges for returned checks, reconnects, and service establishment reflects cost responsibility, and it also moderates increases and takes account of affordability concerns.

132. The Commission has repeatedly determined that costs should be balanced against other ratemaking considerations.

133. SCE's failure to include justification for CSBU capital costs with the application was an inadvertency, not part of a litigation strategy.

134. GRC funding of the energy centers' and the pump test program's capital requirements has not been justified.

135. SCE's participation in the RTEM program as a provider of meters was not mandated by ABX1 29.

136. Because minority participants credits recorded in Account 930 consistently declined from 1997 to 2000 to approximately one-half the 1997 level,

recorded data for 2000 $8.102 million (Labor and Non-labor) are the most representative of test year amounts.

137. A capitalized P&B rate of 27.8% for 2003 appropriately reflects the apparent increasing trend from 1996 to 2000.

138. SCE has not proven that it is reasonable to expect that the level of spending on bankruptcy litigation in 2000 will continue in the test year.

139. Even if all appeals regarding the Filed Rate Doctrine lawsuit were exhausted, the costs SCE incurred are representative of future litigation costs.

140. Legal and regulatory work associated with the energy crisis has been increasing, and a three-year average (1998-2000) for outside counsel expenses in Accounts 923 & 928 is more reliable as a predictor of test year expenses than a two-year average.

141. While SCE should be more efficient in the preparation of its next GRC, the scope of work to be performed in connection with GRCs has been growing.

142. It is not likely that the lower number of board meetings held annually prior to 2000 will resume because certain officers can now call a meeting for any purpose; SCE held more than seven board meetings in 2000, 2001, and 2002; SCE continues to face pressing matters; and the requirements of the Sarbanes-Oxley Act are likely to lead to more board meetings.

143. For nuclear property insurance it is reasonable to use actual instead of forecast data to determine the test year expense.

144. A six-year average is reasonable to estimate nuclear liability insurance refunds for the test year, even though it may actually underestimate the refund.

145. Reducing SCE’s forecast of Business Resources by $491,875 for E&TS non-labor expenses will ensure that ratepayers are not inappropriately charged for celebratory events.

146. A five-year average is a more reliable predictor of test year expenses for the non-labor portion of the Investigations Division because the last recorded year reflects reduced expenses resulting from temporary cost reduction measures implemented in response to the California energy crisis.

147. Reducing the non-labor portion of SCE's request for the Shared Services Support Group by $83,507 gives effect to our concern that ratepayers should not fund lunches for executives and managers and for mentor program participants.

148. SCE agrees that $323,000 for market studies and increased title and mapping services should be removed from Account 921 pursuant to D.99-09-070.

149. ORA has not demonstrated that $96,000 in expenses for landscape maintenance activities such as turf replacement, removal and replacement of ground cover, irrigation work, replacement of dead trees, etc. are nonrecurring.

150. The last recorded year is appropriate to forecast test year expenses for Account 935 – Maintenance of General Plant because SCE's non-electric facilities are aging, and facility age significantly influences maintenance costs.

151. SCE's direct testimony in support of its shared services capital expenditures forecast included approximately 60 pages of text, tables, and figures; SCE provided additional, comprehensive information in response to data requests; and it has not been shown that SCE unreasonably failed to respond to data requests pertaining to this issue.

152. Reconfiguration of GO1 to an open environment reduced the cost of employee moves and improved the utilization of available space at the GO complex.

153. SCE's health benefits program provides full time employees a Preventive Health Account, and it has not been shown that ratepayer funding of the

corporate fitness center, which 250 participants use each day, is a cost-effective means of producing productivity gains that benefits ratepayers.

154. SCE's decision to seismically upgrade its GO2 building was the result of a study, conducted under contract with FEMA, whose findings and recommendations were published in June 2000.

155. The SFP is a separate, specific project of defined purpose and duration, whereas the Various Major Structures blanket work orders provide funding for unplanned occurrences on an ongoing basis.

156. Basing the test year forecast of IT O&M expenses on historical spending patterns is necessary because SCE has not adequately supported its budget-based forecast.

157. Removing Y2K project costs from the recorded IT O&M expense data is inappropriate because SCE temporarily reprioritized other work when the Y2K project was underway, and such work must now be done.

158. Average recorded IT O&M expenditures during 1996-2000 of $107.921 million per year provide the best estimate of test year expenses.

159. Although SCE was able to temporarily delay a portion of Blanket Budget Items IT capital projects to offset Y2K costs, continuing to delay this work is not sustainable, and could impact the company's ability to serve ratepayers.

160. SCE's forecast for IT capital expenditures for Blanket Budget Items is nearly 32% more than the five-year average.

161. SCE has not demonstrated that it is necessary to expect to routinely pay certain IT employees bonuses of nearly $100,000 per year per employee for unspecified future projects.

162. The e-business strategy originally developed with IBM is still evolving, and it is reasonable to expect that SCE will incur as much as $112,388 in the test year for this initiative.

163. SCE's capitalized software contingency of $860,000 for software was based on industry standards and best practices for application development.

164. For non-labor expenses for the Total Compensation Division, a three-year average (1998-2000) results in the most reliable forecast even though the last recorded year is the is the lowest value of the five years from 1996 to 2000.

165. The Commission explicitly provided in D.96-01-011 that the utility must sustain its burden of proving that dues and memberships for organizations such as the Corporate Executive Leadership Board offer ratepayer benefits.

166. The test year forecast for expenses in Account 923 for the HR Service Center should not be based on 1996 data because SCE reduced its workforce that year, HR curtailed activities relating to strategic and operational change initiatives, and 1996 was a start-up year for the HR Service Center.

167. Outside services that help executives understand and appreciate their compensation benefits are of questionable value to ratepayers.

168. Since SCE's total employee compensation is shown to be 4.3% above the comparable market total compensation, and the study margin of error is plus or minus 5%, SCE's total compensation for all employees is presumed to be equivalent to the market level.

169. The total compensation study enables the Commission to determine the level of employee total compensation that reasonably assures that SCE is a competitive employer but that does not provide above-market salary and benefit packages that add unnecessarily to ratepayer costs.

170. The total compensation study process was jointly managed by SCE and ORA, and therefore was not unduly secret.

171. Neither the total compensation study nor any other record evidence provides any basis for concluding that SCE's executive total compensation, including base salary, incentive pay, non-cash compensation, and the Executive Retirement Plan, is unreasonable.

172. There is no evidence that SCE's executive incentive plan produces inappropriate incentives or results in overcollections that would be mitigated by 50/50 sharing.

173. The corollary of this Commission's policy to exclude expenses of utility philanthropic practices from rates is that it will not interject itself into utility management decisions regarding corporate philanthropy, as part of its ratemaking responsibilities.

174. Because the total compensation study explicitly excluded spot bonuses, we cannot conclude that the Spot Bonus program does not result in SCE's overall total compensation being above market level.

175. The Results Sharing program motivates employees to improve performance in areas where such improved performance is in the interests of utility customers.

176. The Results Sharing program has changed considerably since its inception in 1995, and program expenses prior to 1999 are unlikely to be predictive of 2003 expenses. It is therefore most reasonable to utilize a two-year average of actual payouts for 1999 and 2000.

177. SCE's Results Sharing program does not result in total compensation that exceeds competitive employment market levels.

178. There is no evidence that SCE's Results Sharing program creates outcomes that are contrary to ratepayer interests.

179. The ACE program is neither a cultural nor a social activity, but is rather a tool to enhance employee performance that is consistent with ratepayer interests.

180. The use of formal recognition programs such as the ACE program is an established business practice for most companies.

181. The ratio of actuarial to market value of SCE's pension plan rose to 96.2% in 2002 and was projected to be 112.0% in 2003.

182. When investment returns are favorable, actuarial asset returns generally are below market returns; conversely, when investment returns are unfavorable, actuarial asset returns generally are above market value.

183. ORA's smoothing method to mitigate swings in pension contributions not only smoothes investment returns, it also smoothes changes in market value attributable to employer contributions and benefit payments. It is therefore not usable either for ERISA minimum funding purposes or for IRS tax deductibility purposes.

184. SCE's smoothing methodology meets all the criteria established by professional actuarial organizations and the IRS.

185. The last recorded year amount of $30.515 million is the most reliable predictor of SCE's 401(k) program costs for the test year.

186. SCE's redeployment program, which is for employees who become surplus due to business necessity, is not limited to employees impacted by electric industry restructuring.

187. ORA's proposed PBOP-related refund of $100 million relies on the contention that "Contributions" amounts that ORA credits SCE for having made

include all PBOP costs incurred and paid by SCE; however the amounts used by ORA incorrectly exclude "pay-as-you-go" costs for pre-1993 retirees.

188. Although SCE had not contributed to the PBOP trust funds a portion of the accelerated amortization through the Competitive Transition Charge of certain PBOP costs associated with SCE's non-nuclear generation when it filed its testimony, the subject contributions were actually made by year-end 2002, including $41.196 million to complete funding of the accelerated transition obligation.

189. Some PA activities can improve the coordination of the local government/utility interface on development projects, or enforce utility franchise agreement rights, and to the extent that such activities result in lower utility costs, ratepayers can clearly benefit.

190. A disallowance of 50% of the PA costs requested by SCE would give too little weight to the evidence of potential ratepayer benefit of PA activities, whereas a 25% disallowance of SCE's PA request strikes a fair balance of ratepayer and company interests and gives appropriate weight to the fact that a considerable portion of PA activities are at the local level and have significant potential ratepayer benefit.

191. The Santa Barbara County Board of Supervisors unanimously approved a renegotiated franchise agreement on January 21, 2003, which resolves the only contested issue regarding SCE's estimated franchise fee factor.

192. The shareholders of EIX are also the shareholders of SCE, with whom SCE must communicate.

193. Because recorded data from 1996-2000 are of little value in forecasting test year ES&M expenses, a budget-based approach is appropriate.

194. For purposes of estimating ES&M staffing requirements in the test year, ORA's comparative utility analysis is not demonstrated to be a valid comparison across utilities, and its contract-staff ratio analysis relies on unsubstantiated assumptions about the simplicity and uniformity of contracts.

195. ORA may have underestimated the likely number of contracts that ES&M would negotiate in 2003, and not all ES&M work is contract related.

196. The ES&M department will incur additional expenses for procurement risk management that were not included in SCE's forecast.

197. It is not reasonable to assume that even though 53 employees were known to have erroneously charged non-qualifying expenses to ratepayers at a rate of 11.68% of reimbursable expenses, approximately 2,547 employees reported their reimbursable expenses with a zero error rate.

198. Excluding Edison Select costs associated with providing non-tariffed products and services is consistent with D.99-09-070.

199. ORA's recommendation to prohibit temporary assignments of SCE personnel to EME has no ratemaking implications for this GRC, but would require accepting its definition of "energy marketing affiliate," which could potentially implicate the interests of other utilities that did not participate in this GRC.

200. With respect to weighted average plant-in-service balances, the corrected mean weighting percentage over the past nine years was 42.554%, and the reliability of this value as a predictor is reinforced by the median value of 43.54%.

201. Even if there is an increasing trend in M&S, due to the absence of information regarding the cause of any increasing trend a five-year average is a more reliable basis for forecasting M&S.

202. Even though insurance provisions represent prepayments, they are properly included in the lead-lag study to compensate the utility for the use of capital.

203. With respect to property insurance, there are several accounts in addition to FERC Account 924 that must be totaled to arrive at the correct amount to use for the lead-lag study.

204. Even if there is an increasing trend in customer advances, the 1998 change in line extension rules does not necessarily explain the recent increase in this account, and data from 1998 to 2002 would incorporate the effect of the 1998 change.

205. Customer advances are affected by general economic trends, including the level of interest rates, development schedules and higher density construction, and these factors are incorporated into a five-year average but not in a single year's recorded balance.

206. In recent years SCE has had access to a consistent monthly customer deposit balance of at least $60 million and as much as $142 million, which represents a substantial and permanent source of working cash provided by ratepayers.

207. As customer deposits are repaid to some customers, other customers submit new deposits; and while there is continuous turnover, the average total daily and monthly customer deposit balances stay relatively constant.

208. Using customer deposits to offset rate base is analogous to the treatment of employee vacation as a permanent source of capital not provided by investors.

209. Circumstances have changed since U-16 was developed, and it is not reasonable to assume that SCE's customer deposit amounts are relatively small and interest rates are relatively large compared to the rate of return on rate base.

210. The Commission has adopted deviations from U-16 in utility-specific rate cases.

211. The circumstances that led the Commission to reject SCE's proposal to rate base fuel inventory are not equivalent to the circumstances attendant to TURN's proposal for customer deposits.

212. Informed judgment on the part of depreciation professionals is a key component of the depreciation studies and analyses of both SCE and TURN.

213. The extensive exercise of subjective and potentially biased judgment by the respective depreciation experts renders their analyses and recommendations unreliable for purposes of ordering major changes in depreciation parameters and expenses in this GRC.

214. Although it is foreseeable that the SONGS 2 & 3 steam generators will require replacement in or near 2012, that eventuality does not necessarily mean that the useful economic life of the SONGS units will be over at that time.

215. Amortization of easements is permissible under the Uniform System of Accounts.

216. Even if SCE has begun to experience retirements associated with easements, it has not presented any analysis of the extent to which easement retirements are occurring.

217. With respect to productivity growth, the sales forecast, cost escalation estimates, and payroll taxes, the parties have either not taken issue with SCE's GRC request or have reached agreement with SCE.

218. A revenue balancing account mechanism is consistent with the objective of ensuring that SCE is not rewarded for increasing commodity sales.

219. Proposals such as SCE’s PTYR mechanism have been approved in energy utility rate proceedings on several occasions over the past 20 years, but not invariably so.

220. The use of a revenue balancing account provides added, though not full, justification for an attrition allowance or similar revenue requirement adjustment mechanism.

221. SCE’s financial condition was devastated by the events of 2000 and 2001, it only narrowly avoided bankruptcy, and it is still working to regain full creditworthiness.

222. Low productivity gains and customer growth cost impacts constitute justification for excluding a specific productivity adjustment from the PTYR mechanism in this GRC cycle.

223. Aglet would limit SCE’s cost recovery for SONGS 2&3 outages in 2004 to the adopted costs for one outage, even if more than one outage is reasonably forecast.

224. Allowing post-test year rate changes based on budgets could have the effect of allowing large blocks of capital into rates without meaningful review; and it could give SCE strong incentives to inflate its spending plans without real intention to build, or to delay startup of needed plant construction.

225. When older facilities are replaced with new ones, the associated costs are typically much higher that what is included in rates for the original facilities, and the effect of this phenomenon is enhanced by the accelerated pace of planned capital spending associated with the SCE’s infrastructure replacement program during the PTYR period.

226. The use of historical capital spending incorporates the lower capital additions from SCE’s financial crisis years, and it may not adequately reflect the

increased pace of capital investments associated with the infrastructure replacement program in the PTYR period.

227. A PTYR forecast based solely upon historical averages may understate the reasonable capital spending needs for the PTYR period of this GRC cycle, assuming that SCE actually carries out its spending plan.

228. Simplicity and accessibility of the CPI as a measure of general inflation faced by urban U.S. consumers do not make the CPI an appropriate measure of price changes faced by an electric utility.

229. The CPI does not specifically cover the prices of the typical goods SCE purchases, and it excludes the prices of health care paid for by employers.

230. It is reasonable to continue the Z-Factor mechanism as part of the PTYR mechanism with the return to more conventional cost-of-service ratemaking.

231. Under the adopted PTYR mechanism, annual implementation filings involve the application of escalation factors using data available from commercial sources; and, with respect to areas where utility discretion and judgment is involved, such as the PTYR capital additions forecasts and SONGS 2 & 3 outage forecasts, we are adopting true up provisions that protect ratepayers.

232. The Commission resolved issues pertaining to the labor and multifactor allocation methods in D.03-08-062, and in effect approved the labor allocation method used by FERC.

233. A properly structured incentive program that is layered on top of cost-of-service ratemaking can be a targeted regulatory mechanism that promotes improvement and discourages retrogression in these important areas as these deviations occur.

234. SCE has not reconciled its claimed ability to identify effective customer service options when they are called for with its position that ratemaking

performance incentives are needed to provide adequate customer satisfaction in other respects.

235. SCE has not reconciled its preference for ratemaking performance incentives to improve reliability over prescriptive regulations with the fact that the prescriptive regulations it finds stifling will remain in place.

236. SCE has not reconciled its claim that safety is its top priority, and its claim that it has decided to pursue employee safety at a level significantly in excess of that needed to meet PBR goals, with its position that ratemaking performance incentives are required to achieve a lesser standard of employee safety.

237. While there remained considerable policy uncertainty affecting SCE's organizational, strategic, and investment choices in the areas of procurement, generation, and resource planning, SCE has been taking reasonable steps to position itself to respond to evolving policy determinations.

238. If and when the Commission considers the desirability of having utilities construct new generation subject to cost-of-service ratemaking, there will be a need to consider an explicit framework governing risk allocation, rate of return, cost recovery, length of the arrangement, and disposition of any residual value.

239. SCE conducts a comprehensive outreach program in its efforts to achieve GO 156 participation goals, and there is no evidence showing that SCE's efforts to achieve GO 156 participation goals are in any way inadequate.

240. Between 1990 and 2002 SCE made significant progress in increasing the diversity of its overall workforce, and, with certain exceptions, this progress applied to most minority groups and job classifications.

241. SCE has adopted and embraced policies and practices that will continue to address areas of under-representation throughout its workforce.

242. SCE's uncontested proposal for disposition of the GRC RRMA balance and for related rate recovery appropriately balances the interests of the utility and its ratepayers by leaving them essentially indifferent to the actual date of this decision.

243. The base rate revenue requirement for test year 2003 set forth in Appendix C is just and reasonable.

244. The current Total Compensation study does not reflect the public trust responsibilities related to compensation of regulated utility executives

245. Filed reports of total compensation for top executives would improve the Commission's ability to assess the appropriateness of executive compensation.

## Conclusions of Law

1. In presenting their initial rate case showings, utilities should work to provide the necessary details and justification with due attention to the need for economy of words.

2. With respect to uncontested issues not explicitly addressed in the foregoing discussion, SCE has made a *prima facie* showing of justness and reasonableness.

3. Capital expenditures forecasts for SONGS 2 & 3 of $44.409 million (SCE share) for 2004 and $41.311 million (SCE share) for 2005 should be adopted.

4. A test year 2003 SONGS 2 & 3 base O&M forecast of $139.987 million should be adopted.

5. A per unit per outage cost estimate of $52.462 million (2000 dollars, 100% level) for SONGS refueling and maintenance outage-related expenses should be adopted.

6. Palo Verde capital expenditures of $19.4 million for 2003 and the Palo Verde O&M expense forecast of $39.517 million should be adopted.

7. Whether or not Mohave continues to operate after 2005, we intend to authorize the capital funding that is necessary for continued safe, reliable, and environmentally responsible operation of the plant through 2005.

8. Mohave capital expenditures of $17.887 million for 2002 and 2003 and Mohave O&M expenses of $30.633 million for 2003 should be adopted.

9. Four Corners capital expenditures of $9.173 million in 2002 and $4.462 million in 2003, and Four Corners O&M expenses of $20.798 million for 2003 ($23.182 less $2.384 million) should be adopted.

10. Hydro capital spending of $32.812 million for 2002 and 2003 and hydro O&M expenses of $25.661 million plus $845,000 for Florence Dam buttress repairs should be approved.

11. SCE's test year O&M forecast of $1.518 million for Other Generation and its capital expenditures forecast, reduced by $445,000 for a fuel pier project, are reasonable and should be adopted.

12. It is no longer appropriate to hold the utility to the Section 367 requirement that capital additions be necessary to maintain the facilities only through 2001, or to the D.97-09-048 requirement that capital additions to improve the unit's heat rate be excluded.

13. The general rule for reasonableness review, i.e., that reasonableness should be evaluated on the basis of facts and circumstances known or knowable when the utility made the decision to make the addition, is inapplicable to the question of whether the review standards of Section 367 and D.97-09-048 should be applied to SCE's 1997-98 non-nuclear generation capital additions.

14. SCE's proposal for recovery of the 1997-98 non-nuclear generation capital additions of $30.937 million should be approved.

15. It is reasonable for regulators to take steps to avoid the creation of an overly reliable T&D system that adds unnecessarily to ratepayer costs.

16. An adjustment of $1.443 million per year for FERC Account 583.400 is adopted to give effect ratemaking principle that ratepayers should not be required to pay a second time for activities explicitly authorized by the Commission in the past, and to reflect a forecast of 125,000 intrusive inspections per year through 2006.

17. A capital forecast disallowance of $3.447 million for pole replacements is reasonable in view of SCE's failure to perform intrusive inspections that it was funded and required to perform. In addition, SCE's T&D capital forecast should be reduced by $4.968 million for 2002 and $5.256 million for 2003 to reflect a wood pole replacement cost of $7,135 per unit.

18. SCE's forecast of T&D plant additions should be adopted along with adjustments for pole replacement costs adopted herein.

19. SCE's forecast for T&D O&M expenses should be adopted with adjustments of $1.443 million per year for FERC Account 583.400 (intrusive inspections), $1.904 million for Account 582 (forecasting methodology), and $1.868 million for Account 588 (electric transportation).

20. SCE is placed on notice that, in the event that the Commission further considers the line and service extension rules, SCE cannot escape its responsibility to provide the Commission and parties documentation necessary to determine total line extension job costs recorded to rate base, versus total estimated costs and total allowances for the same work orders.

21. SCE has not met its burden to show how ratepayers would benefit from the purchase of 450 electric vehicles or equivalent credits when purchase of less

expensive vehicles could satisfy EPAct, and therefore has not justified its budget-based forecast for Account 588.

22. SCE should continue to ensure that its criteria for locating and establishing APAs, as well as ORA's criteria, are implemented.

23. Because SCE has not met its burden of showing that improved Internet capability will not affect other customer information revenue requirements, a disallowance of $340,000 is reasonable.

24. Because SCE has failed to establish that its RIM test analysis provides a valid demonstration of ratepayer benefit, pursuant to Section 740.4 we are bound to deny its E&BD funding request.

25. SCE should convene a workshop to explore whether and how SCE's third party financing can be made effectively available to local governments.

26. SCE should ensure that the content of bill inserts and similar notices is posted on its website in a manner accessible to customers.

27. SCE is authorized to implement a residential LPC consistent with the foregoing discussion and findings, provided that CARE customers will be exempted from its application.

28. ORA's proposed schedule of service charges for returned checks, reconnects, and service establishment is reasonable and should be adopted.

29. Due to the circumstances of this case, SCE's justification for CSBU capital costs should be considered on the merits rather dismissed on procedural grounds.

30. A disallowance of $10.8 million in capital expenditures associated with SCE's participation in the RTEM program should be approved.

31. Because SCE overlooked adjustments required pursuant to the gross revenue sharing mechanism adopted by D.99-09-070, SCE should certify in an

advice letter filing that none of its GRC requests include expenses that, pursuant to D.99-09-070, are to be borne by shareholders.

32. As long as the utility's total compensation package is reasonable, and incentive plans do not produce outcomes that are contrary to ratepayer interests, the allocation of that compensation among cash, benefits, and long-term incentives should be left to utility management's discretion.

33. For its next GRC, SCE should conduct a study, using appropriate statistical methodology, of reporting errors for reimbursable expenses of all employees, including those not subject to GO 77K reporting requirements.

34. The average plant weighting factor of 42.554% is reasonable and should be adopted.

35. Based upon the average M&S for the years 1998 through 2002, and the addition of $6.5 million for Palo Verde M&S, a forecast of $62.590 million for M&S should be adopted.

36. TURN's uncontested recommendations to adjust working cash for Employee Withholding and Accrued Vacation ($5.166 million), arithmetic corrections ($1.039 million), and labor lag in the lead-lag study by 1.22 days ($2.227 million) should be adopted, whereas TURN's proposal to remove insurance provisions from the lead-lag study should be rejected.

37. Because averaging is more appropriate than a single year's data to estimate customer advances, SCE's revised forecast of $45.503 million should be adopted.

38. An estimate of $117.174 million for customer deposits should be adopted balance as an offset to rate base, and SCE's operating expenses should be increased by $2.343 million to reflect interest payable on customer deposits at a projected interest rate of 2%.

39. Neither SCE nor TURN has sustained their respective burdens of proving that their depreciation proposals are justified.

40. In the absence of an acceptable alternative in this GRC to using the currently authorized depreciation rates, those rates should continue to be used.

41. For its next GRC, SCE should present a depreciation study that is based on a joint SCE/ORA management approach similar to that used for total compensation studies. SCE should, at the outset of the study design process, convene a workshop providing opportunity for interested parties to participate.

42. SCE's showing on productivity is accepted, a sales forecast of 79,795 GWh is adopted, the cost escalation factors in Exhibit 412 shall be applied, and SCE's revised estimate of payroll taxes is adopted.

43. SCE's PTYR filings for 2004 and 2005 should reflect the corrections to the results of operations model identified in SCE's April 11, 2003 letter to the assigned ALJ.

44. SCE's revenue balancing account proposal is approved.

45. To judge whether attrition allowances or similar post-test year revenue adjustment provisions are appropriate, we should inquire into whether there are, or will be, conditions that might undermine a utility's opportunity to earn its authorized rate of return after the test year.

46. To provide SCE with a reasonable opportunity to earn the authorized return on utility investments during this GRC cycle, we should adopt a PTYR mechanism applicable for both 2004 and 2005.

47. In any PTYR filing in which it includes costs for SONGS 2 & 3 outages that it forecasts will occur in the following year, SCE should include a proposal for refunding to ratepayers the costs of any outage that was forecast and included in rates but did not occur in that year.

48. Due to problems with both the SCE and the ORA / Aglet approaches to forecasting PTYR capital costs, a modification that combines elements of both approaches should be adopted as set forth in the foregoing discussion. SCE is authorized to include the capital costs associated with its budget-based forecast in its PTYR filings, but rates (or revenue requirements) will be subject to refund to the extent that they exceed rates (or revenue requirements) that would be associated with the baseline forecast which is defined as ORA's capital forecasts for 2004 and 2005.

49. We authorize SCE to file for PTYR adjustments in this GRC cycle through advice letters only if the proposed increases do not exceed $150 million or 5%; otherwise, a formal application shall be filed.

50. For consistency with D.03-08-062, the jurisdictional allocation should be based upon the labor allocation method.

51. Targeted performance incentives, both positive and negative, provide a more responsive approach to deviations in service adequacy and quality than our other ratemaking mechanisms. CUE's proposals to implement such performance incentives shall be approved.

52. SCE's July 18, 2003 motion regarding disposition of the GRC RRMA balance and related rate recovery should be granted.

53. The Commission should direct SCE to develop a new Total Compensation study consistent with the concerns set forth in this decision.

54. SCE should be ordered to report annually on the total compensation packages for each of the top ten executives.

## O R D E R

**IT IS ORDERED** that:

1. Application (A.) 02-05-004 is granted to the extent set forth in this Order. Southern California Edison Company (SCE) is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2003 test year base rate revenue requirements set forth in Appendix C to the extent set forth in Ordering Paragraph 2.

2. SCE's July 18, 2003 motion regarding disposition of the General Rate Case Revenue Requirement Memorandum Account (GRC RRMA) balance and related rate recovery is granted. Effective with the effective date of this decision, the GRC RRMA balance shall be transferred to the Base Revenue Requirement Balancing Account (BRRBA) and differences between authorized GRC revenue requirements and recorded GRC-related revenues shall be recorded in the BRRBA. The test year base revenue requirement authorized herein shall be included in rate levels along with the balance in the BRRBA such that the BRRBA balance is fully amortized within 12 months. SCE is authorized to adjust its rates on a System Average Percentage Change basis pursuant to Decision (D.) 03-07-029. In order to minimize the number of rate changes, SCE is authorized to consolidate rate changes authorized herein with those authorized not later than April 30, 2004 in other proceedings and by this decision for 2004 pursuant to the Post-Test Year Ratemaking (PTYR) mechanism as approved in this Order.

3. SCE is authorized to recover $30.937 million for 1997-98 generation capital additions removed from A.99-04-024 to this docket by Administrative Law Judges' Ruling dated September 9, 2002. SCE shall include in the advice letter filing it makes pursuant to this order a demonstration that the costs associated with the 1997-98 capital additions are not double counted in rate base. SCE is

authorized to transfer the return and applicable taxes (including interest) recorded in the Non-Nuclear Generation Capital Additions Memorandum Account related to the $30.937 million of 1997-98 capital additions to the BRRBA.

4. SCE is authorized to establish the proposed Air Conditioning Cycling Device One-Way balancing account.

5. SCE is authorized to establish a Late Payment charge that exempts CARE customers and to revise its Returned Check, Reconnect, Service Establishment, and Field Assignment charges in accordance with the foregoing discussion, findings, and conclusions. SCE is authorized to establish the proposed Late Payment Charge Revenue Balancing Account.

6. Within 10 days of the effective date of this order, SCE shall file revised tariff sheets to implement the revenue requirements, accounting procedures, and charges authorized in this Order and to incorporate the relevant findings and conclusions of this decision. The revised tariff sheets shall become effective on filing, subject to a finding of compliance by the Energy Division, and shall comply with General Order 96-A. The revised tariff sheets shall apply to service rendered on or after their effective date.

7. SCE is authorized to implement its proposed revenue balancing account to adjust for sales variations and its proposed PTYR mechanism for both 2004 and 2005 to the extent consistent with the foregoing discussion, findings of fact, and conclusions of law. In connection with the PTYR mechanism, SCE is authorized to establish for San Onofre Nuclear Generation Station Units 2 & 3 (SONGS 2 & 3) a Flexible Refueling Schedule mechanism that comports with the foregoing discussion, findings, and conclusions. In any PTYR filing in which it includes costs for SONGS 2 & 3 outages that it forecasts will occur in the following year, SCE shall include a proposal for refunding to ratepayers the costs of any SONGS

2 & 3 outage that was forecast and included in rates but did not occur in that year. SCE's PTYR filings shall include a proposed accounting mechanism to implement the "subject to refund" provision of the capital recovery component of this adopted PTYR mechanism.

8. Effective with the effective date of this decision, SONGS 2 & 3 plant shall be included in rate base, general rate case revenue requirements shall be adjusted to include SONGS 2 & 3 costs that are recovered through the (Incremental Cost Incentive Procedure (ICIP) mechanism, and the ICIP mechanism shall be eliminated.

9. SCE shall certify in an advice letter filing that none of its GRC requests include expenses that, pursuant to D.99-09-070, are to be borne by shareholders. Said certification shall either be included with the advice letter filing made pursuant to this decision or in a separate advice letter filing due not later than 60 days from the date of this order. In the event that SCE uses this alternative, the revenue requirement authorized herein is subject to refund of any amounts incorrectly included in violation of D.99-09-070.

10. Consistent with the foregoing discussion and findings, SCE shall, not later than 90 days after the effective date of this order, provide notice of and convene a workshop to explore whether and how SCE's third-party financing can be made effectively available to local governments.

11. Whenever SCE files a rate proposal before this Commission that requires a bill insert or similar notice to customers, SCE shall ensure that the content of the notice is also posted on its internet website in a manner accessible to customers.

12. SCE shall establish a mandatory customer service guarantee program as outlined and directed in Section 5.5 of this Decision within 120 days of the

effective date of this order, including the reporting requirements incorporated therein.

13. The joint motion of SCE and Coalition of California Utility Employees for approval of settlement on employee safety and distribution reliability performance incentive mechanisms is denied.

14. CUE's proposals for incentive mechanism, without deadbands, as outlined in Section 13 of this order are approved.

15. SCE shall include the following with its next general rate case (GRC) filing, consistent with the foregoing discussion:

a. Transmission and distribution cost/reliability tradeoff and value-of-service analyses.

b. A report on the feasibility of replacing or supplementing the Authorized Payment Agency/Local Business Office network with automated payment processing.

c. A study, using appropriate statistical methodology, of reporting errors for reimbursable expenses of all employees, including those not subject to GO 77K reporting requirements.

d. A depreciation study that is based on a joint SCE/Office of Ratepayer Advocates management approach similar to that used for total compensation studies. SCE shall, at the outset of the study design process, convene a workshop providing opportunity for interested parties to participate.

e. An updated report on the supplier diversity program, including but not limited to the Disabled Veterans Business Enterprise component.

f. An updated report on its workforce diversity program.

16. San Diego Gas & Electric Company's proposals for cost recovery for its share of SONGS capital costs and O&M expenses are approved, subject to adjustments necessary to reflect the corresponding adopted costs and expenses.

17. SCE shall develop a new Total Compensation study, consistent with the concerns set forth in this decision, for use in its next General Rate Case.

18. No later than February 1st of each year, SCE shall report to the Commission on the total compensation received by each of its ten most highly compensated executives. This information shall also be made publicly available at the same time.

19. Phase 1 of this proceeding is concluded. This proceeding remains open for consideration of Phase 2 issues.

This order is effective today.

Dated ___________________________, at San Francisco, California.

## APPENDIX A
## List of Appearances

Applicant: Frank J. Cooley, Attorney at Law, and Russell G. Worden, for Southern California Edison Company.

Interested Parties: Barkovich and Yap, Inc., by Barbara R. Barkovich, for California Large Energy Consumers Association; William H. Booth, Attorney at Law, for California Large Energy Consumers Association; Ellison, Schneider & Harris, by Andrew B. Brown, for California Department of General Services and by Douglas K. Kerner, Attorney at Law, for Independent Energy Producers; Maurice Brubaker, for Brubaker & Associates, Inc.; McCracken, Byers & Haesloop, by David J. Byers and Beth C. Tenney, Attorneys at Law, for California City-County Street Light Association; Downey, Brand, Seymour & Rohwer, LLP, by Dan L. Carroll and Ann L. Trowbridge, Attorneys at Law, for California Industrial Users; Sheryl Carter, for Natural Resources Defense Council; Steefel, Levitt & Weiss, by Mark Fogelman, Attorney at Law, for The Navajo Nation; Department of the Navy, by Norman J. Furuta, Attorney at Law, for Federal Executive Agencies; Arnold & Porter, by James I. Ham, Attorney at Law, for The Hopi Tribe; Morrison & Foerster, LLP, by Peter Hanschen, Attorney at Law, for Agricultural Energy Consumers Association; Marcel Hawiger, Attorney at Law, for The Utility Reform Network (TURN); Adams, Broadwell, Joseph & Cardozo, by Marc D. Joseph, Attorney at Law, and David Marcus, for Coalition of California Utility Employees; Elizabeth L. Leavengood, Attorney at Law, for The Office of Ratepayer Advocates; Ronald Liebert, Attorney at Law, for California Farm Bureau Federation; Grueneich Resource Advocates; by Jody London, for University of California and California State University and Michael McCormick, for The Irvine Company; Sutherland, Asbill & Brennan, LLP, by Keith R. McCrea, Attorney at Law, for California Manufacturers & Technology Association; Jeff Nahigian and Bill Marcus (JBS Energy, Inc.), for TURN; Alcantar & Kahl, by Nora E. Sheriff, Attorney at Law, for Donald Brookhyser of Alcantar & Kahl's Portland, OR office and James Roos, RCS, Inc.; James Weil, Director, for Aglet Consumer Alliance; Steve Nelson and Vicki L. Thompson, Attorneys at Law, and Bruce J. Williams, for San Diego Gas & Electric; Manatt, Phelps & Phillips, LLP, by Roger Berliner, for the County of Los Angeles and by David L. Huard, for City of Corona, Catholic Health Care West and Los Angeles Unified School District, and by

Randall W. Keen, Attorney at Law, for Del Taco; Kay Davoodi, for Navy Rate Intervention; Steven Moss, for Agricultural Energy Consumers Association; Reed V. Schmidt, Bartle Wells Associates, for California City-County Street Light Association; Gail L. Slocum, Attorney at Law, for Pacific Gas and Electric Company.

Intervenors: Manatt, Phelps & Phillips, LLP, by David L. Huard, for City of Corona and Los Angeles Unified School District, and by Randall W. Keen, Attorney at Law, for Catholic Healthcare West, Del Taco; Anderson & Poole, by Edward G. Poole, Attorney at Law, for California Independent Petroleum Association and Western Manufactured Housing Communities Association; Itzel Berrio, Attorney at Law, for the Greenlining Institute; Daniel W. Douglass, Attorney at Law, for Western Power Trading Forum; Robert Finkelstein, Attorney at Law, for The Utility Reform Network; Law Offices of Daniel W. Douglass, by Gregory Klatt, Attorney at Law, for Alliance for Retail Energy Markets; and McCarthy & Berlin, LLP, by C. Susie Berlin, Attorney at Law, for City of Anaheim

State Service: Laura L. Krannawitter, for the Executive Division; Donald J. LaFrenz and Laura A. Martin, for the Energy Division, David K. Fukutome, Sean F. Casey, Christopher Danforth, Dexter E. Khoury and Robert M. Pocta, for Office of Ratepayer Advocates; and Jonathan M. Teague, for Department of General Services.

**(END OF APPENDIX A)**

## APPENDIX B
## List of Acronyms and Abbreviations

A. - Application

AB – Assembly Bill

A&G – Administrative and General

ACE – Awards to Celebrate Excellence

ACMI – Average Customer Minutes of Interruption

ADA – Americans with Disabilities Act

AFVs – Alternative Fueled Vehicles

Aglet – Aglet Consumer Alliance

ALJ – Administrative Law Judge

APAs – Authorized Payment Agencies

APS – Arizona Public Service

BRRBA – Base Revenue Requirement Balancing Account

CARE – California Alternate Rates for Energy

CCC – California Coastal Commission

CDP – Coastal Development Permit

CEC – California Energy Commission

CEO – Chief Operating Officer

CPI – Customer Price Index

CS&EPP – Corporate Security and Emergency Planning and Preparedness Unit

CS&I – Customer Service and Information

CSBU – Customer Service Business Unit

CTC – Competition Transition Charge

CUE – California Utility Employees

D. - Decision

DRA – Division of Ratepayer Advocates

DSM - Demand-Side Management

DVBEA – Disabled Veterans Business Enterprise Alliance

DWR – Department of Water Resources

E&BD – Economic and Business Development

EDI – Electronic Data Interchange

EIX – Edison International

EME – Edison Mission Energy

EPAct – Energy Policy Act

ERISA – Employee Retirement Income Security Act

ERRA – Energy Resources Recovery Account

E&TS – Event and Travel Services

ES&M – Energy Supply and Management

ESP – Electric Service Provider

ET – Electric Transportation

ETP – Employment Training Program

FEMA – Federal Emergency Management Agency

FERC – Federal Energy Regulatory Commission

Four Corners – Four Corners Generation Station Units 4 and 5

FTEs - Full Time Equivalents

G&I – General and Intangible

GO – General Office

GRC – General Rate Case

Greenlining – Greenlining Institute

GWh - Gigawatthour

HR – Human Resources

Hydro – Hyroelectric

I. - Investigation

ICIP – Incremental Cost Incentive Program

INPO – Institute of Nuclear Power Operations

IR – Infrastructure Replacement

IRP – Infrastructure Replacement Program

ISO – Independent System Operator

IT – Information Technology

KWh – kilowatt-hour

LA County – County of Los Angeles

LBOs – Local Business Offices

LDVs – Light Duty Vehicles

LEV – Low-Emission Vehicle

LPC – Late Payment Charge

M&S – Materials and Supplies

MIP – Master Insurance Program

Mohave – Mohave Generating Station Units 1 and 2

NARUC - National Association of Regulatory Utility Commissioners

NEI – Nuclear Energy Institute

NEIL – Nuclear Electric Insurance Limited

NRC – Nuclear Regulatory Commission

NRDC – Natural Resources Defense Council

NRR - Nuclear Rate Regulation

O&M – Operations and Maintenance

OOR – Other Operating Revenue

OMSE – Outage Management System Enhancement

ORA – Office of Ratepayer Advocates

PA – Public Affairs

P&B – Pension and Benefits

Palo Verde – Palo Verde Nuclear Generating Station Units 1, 2, and 3

PAMM – Procurement and Material Management

PBOP - Post-Retirement Benefits Other Than Pensions

PBR – Performance-Based Ratemaking

PGC – Public Goods Charge

PG&E – Pacific Gas and Electric Company

PIP - Performance Incentive Plan

PROACT – Procurement Related Obligations Account

PTYR – Post-Test Year Ratemaking

PWR – Pressurized Water Reactors

PX – Power Exchange

RFO – Refueling Outage

RIM – Rate Impact Measure

RTEM – Real-Time Energy Metering

SAFSTOR - Safe Long-Term Protective Storage

SAPC – System Average Percentage Change

SCE – Southern California Edison Company

SDG&E – San Diego Gas & Electric Company

SFP – Strategic Facilities Plan

SIPC – Site Integrated Project Committee

SMSA – Standard Metropolitan Statistical Area

SoCalGas – Southern California Gas Company

SONGS – San Onofre Nuclear Generating Station

SPR – Stimulated Plant Records

T&D – Transmission and Distribution

TDBU – Transmission and Distribution Business Unit

TRRRMA – Transmission Revenue Requirement Reclassification Memorandum Account

TURN – The Utility Reform Network

WMDVBE – Women, Minority and Disabled Veterans Business Enterprise

WMS – Work Management System

VAN – Value Added Network

Y2K – Year 2000

(END OF APPENDIX B)

# APPENDIX C

**(END OF APPENDIX C)**

**A.02-05-004 and I.02-06-002 (Email listing)**

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## CERTIFICATE OF SERVICE

I certify that I have by ***electronic***, and by ***U.S. mail,*** served to the parties of which an electronic mail address has been provided, a true copy of the original attached ***OPINION ON BASE RATE REVENUE REQUIREMENT AND OTHER PHASE 1 ISSUES*** on all parties of record for proceedings A.02-05-004 and I.02-06-002 or their attorneys of record.

Dated February 13, 2004, at San Francisco, California.

/s/ SUSIE TOY
Susie Toy

## N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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