Decision **PROPOSED DECISION OF ALJ FUKUTOME** **(Mailed 1/17/2006)**

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 2006, And to Reflect That Increase in Rates.	Application 04-12-014 (Filed December 21, 2004)
Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Southern California Edison Company.	Investigation 05-05-024 (Filed May 26, 2005)

(*See* Appendix A for a List of Appearances.)

OPINION ON SOUTHERN CALIFORNIA EDISON COMPANY'S TEST YEAR 2006 GENERAL RATE INCREASE REQUEST

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OPINION ON SOUTHERN CALIFORNIA EDISON COMPANY'S TEST YEAR 2006 GENERAL RATE INCREASE REQUEST

1. Introduction

1.1 Summary of Decision

This decision addresses the general rate increase request of the Southern California Edison Company (SCE). For test year 2006, SCE is authorized a revenue requirement of $3,704,039,000, which reflects an increase of $287,862,000 or 8.43% over the previously authorized level of $3,416,177,000. The adopted methodology for calculating post-test year revenue requirements results in additional revenue requirement increases of $137,982,000 (3.73%) for post-test year 2007 and $190,141,000 (4.95%) for post-test year 2008. On a general rate case (GRC) revenue basis, when reflecting the effect of increased sales for the test year and post-test years, the revenue increases amount to $228,202,000 (6.57%) for 2006, $68,173,000 (1.81%) for 2007 and $101,623,000 (2.59%) for 2008. On a total system revenue basis, the revenue increases amount to 2.29% for 2006, 0.67% for 2007 and 0.98% for 2008. For test year 2006, this decision also reflects a one-time $139,559,000 reduction for an overcollection in post-retirement benefits other than pensions (PBOPs).[1]

In brief summary, the decision also:

- Assumes a temporary shutdown of the Mohave Generating Station (Mohave) and reflects costs for this scenario, as forecasted by SCE. All costs will be booked to a two-way balancing account and will be subject to reasonableness review.

[1] This results in a reduced revenue increase of $88,643,000 for 2006 (2.55% on a GRC revenue basis or 0.89% on a total system revenue basis). Since it is a one-time reduction, there would be a corresponding revenue increase in 2007.

- Orders SCE to establish a Mohave Sulfur Credit Sub-Account to accumulate revenues from the sale of any sulfur credits created by the December 31, 2005 Mohave closure. Funds should not be disbursed from this sub-account without specific Commission authorization to do so. The issue of the distribution of revenues accumulated in the Mohave Sulfur Credit Sub-Account will be addressed in a separate proceeding when more information on the future operating status of Mohave is known
- Excludes costs for SCE's proposed Project Development Division in rates, but allows SCE to establish a memorandum account to track those costs that support new generation and are not associated with proposed projects. SCE can then seek to include those supportive costs in future rates.
- Approves a stipulation regarding Priority 5 maintenance activities. Such activities will continue to be performed on an opportunity basis, while SCE and the Commission's Consumer Protection and Safety Division work out the details to implement a new maintenance program.
- Assigns a 50%/50% sharing of costs between ratepayers and shareholders for the Results Sharing costs. This sharing is based on our determination of the relative benefits and costs of the program. A similar sharing is adopted for the Executive Incentive Compensation Plan.
- Adopts The Utility Reform Network's (TURN) recommendation to recognize, for ratemaking purposes, the regulatory liability associated with plant removal costs that do not meet the definition of an Asset Retirement Obligation.
- Adopts the Division of Ratepayer Advocates' (DRA's) proposed net salvage rates for calculating depreciation expense, with the exception of Account 364, distribution poles, towers and fixtures. For

Account 364, the decision adopts a compromise net salvage rate proposed by SCE.

- Accepts SCE's forecasted plant additions for 2004 and 2005, subject to a truing up process if the recorded additions are less than forecasted. The truing up process will be performed in conjunction with the Capital Additions Adjustment Mechanism review that will be conducted later this year.
- Rejects proposals to determine the post-test year revenue increases by applying a consumer price index factor to the adopted 2006 revenue requirement. The decision also rejects SCE's proposal to reflect its proposed capital budgets for 2007 and 2008 in determining the revenue increases for the post-test years. Plant additions are instead determined by taking the adopted 2006 test year plant additions and escalating that amount to 2007 and 2008 post-test year dollars.
- Rejects the proposal of San Diego Gas & Electric Company (SDG&E) to establish a Cost Control Incentive Mechanism (CCIM) for the San Onofre Nuclear Generating Station (SONGS).
- Approves a settlement regarding a Reliability Investment Incentive Mechanism.
- Approves a settlement regarding bill calculation services for submetered mobile home parks.
- Reflects SCE's 2006 cost of capital as authorized Decision (D.) 05-12-043.

1.2 Procedural Background

On December 21, 2004, SCE filed Application (A.) 04-12-014 requesting a $568,773,000 revenue requirement increase for test year 2006, based on a proposed base revenue requirement level of $4,060,932,000. Based on its proposed methodology for calculation post-test year revenue requirements, SCE estimated revenue requirement increases of $224,829,000 for post-test year 2007

and $207,273,000 for post-test year 2008. On a GRC revenue basis, the request reflected an increase of $509,962,000 for 2006, $159,448,000 for 2007 and $121,521,000 for 2008.[2] During the course of this proceeding, SCE has reduced its forecast of the 2006 base revenue requirement level and reflected its 2005 authorized rate increase. SCE now seeks a $524,048,000 revenue requiremement increase (15.23%) for test year 2006, based on a proposed base revenue requirement level of $3,963,902,000, and additional post-test year increases of $178,155,000 (4.49%) for 2007 and $201,321,000 (4.86%) for 2008. On a GRC revenue basis, the requested increases now amount to $464,388,000 (13.27%) for 2006[3], $108,346,000 (2.69%) for 2007 and $112,803,000 (2.67%) for 2008. On a total system revenue basis, the requested increases amount to 4.65% for 2006, 1.07% for 2007 and 1.09% for 2008.

On May 26, 2005, Investigation (I.) 05-05-024 was instituted to allow the Commission to hear proposals other than those of SCE and to enable the Commission to enter orders on matters not proposed by SCE. Application 04-12-014 and I.05-05-024 were consolidated for these purposes.

Prehearing Conferences were held on February 18, 2005, May 6, 2005 and June 6, 2005. During May, 2005, public participation hearings were held in Rosemead, Fullerton, San Bernardino, Palm Springs and Visalia. There were 23 days of evidentiary hearings held from June 7, 2005 to July 14, 2005. An additional day of hearing was held on September 12, 2005. Opening briefs were

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[2] Reflection of the PBOP overcollection results in an increase of $370,403,000 in 2006.

[3] Reflection of the PBOP overcollection results in an increase of $324,829,000 in 2006, which is 9.28% on a GRC basis and 3.26% on a total system basis.

filed on August 12, 2005 and reply briefs were filed on September 2, 2005. An evidentiary update hearing was held on October 11, 2005. Update related briefs were then filed on October 21, 2005. The proceeding was submitted for decision on November 30, 2005 after replies to comments on a stipulation regarding a reliability investment incentive mechanism were received.

In addition to SCE, the active parties in this proceeding were the DRA,[4] Aglet Consumer Alliance (Aglet), TURN, SDG&E, the Coalition of California Utility Employees (CUE), The Greenlining Institute (Greenlining), Pacific Gas and Electric Company (PG&E), the Alliance for Retail Energy Markets (AReM), the Direct Access Customer Coalition (DACC), the Western Power Trading Forum (WTPF), the Independent Energy Producers Association (IEPA), and the Western Manufactured Housing Community Association (WMA). The positions taken by the parties are described throughout this opinion.

With the exception of WMA, the parties have taken positions that affect the forecast of SCE's base rate revenue requirement. As set forth in the August 2005 Joint Comparison Exhibit (Exhibit 899), DRA's base rate revenue requirement recommendation for 2003 is $3,592,407,000 or $387,482,000 less than SCE's request at that time.[5] DRA was the only party, other than SCE, to make a full revenue requirement presentation. Due to the complexities of calculating

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[4] As of January 2006, the Office of Ratepayer Advocates (ORA) became the DRA.

[5] This does not reflect SCE's final recommendation as set forth in the October 5, 2005 update testimony (Exhibit 171), because that exhibit does not include an updated calculation of DRA's revenue requirement recommendation. However, we expect the final difference between SCE's and DRA's recommendations to be similar to the $387,482,000 difference calculated in August 2005.

revenue requirements reflecting parties' positions on the various underlying components, the Joint Comparison Exhibit does not include a calculation of the revenue requirement recommendations associated with the positions of parties other than DRA and SCE.

2. Preliminary Matters

2.1 SCE's Showing

Pub. Util. Code § 451 provides, in part, that "all charges demanded or received by any public utility … shall be just and reasonable." Section 454 provides, "Except as provided in § 455, no public utility shall change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified." Where a utility fails to demonstrate that its proposed revenue requirements are just and reasonable, the Commission has the authority to protect ratepayers by disallowing expenditures that the Commission finds unreasonable.

As the applicant, 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.[6] SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application. Intervenors do not have the burden of proving the unreasonableness of SCE's showing.

As in the last GRC, SCE has provided substantial testimony and workpapers to support its request. In D.04-07-022, we requested that in

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[6] "[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.)

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 were not in any way retreating from our prior policy of requiring better initial utility showings. We were 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. SCE appears to have considered this request in preparing its testimony and supporting workpapers. There appears to be less tangentially relevant and duplicative materials included in the company's showing.

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.[7]

2.2 SCE's Financial Health

SCE admits that its financial condition has improved considerably since the financial crisis of 2000-2001, but states that its credit ratings "are not yet back to pre-crisis levels" and that it could be downgraded if there is a reversal of the current trend of increasing regulatory consistency.[8] Among other things, SCE requests approval of its proposed post-test year ratemaking mechanism for 2007 and 2008 in order to "continue SCE's return to financial health."[9]

From November 1992 through December 2000, SCE held an A+ rating from Standard & Poors, a major credit rating agency. Ratings declined

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[7] In this context, "uncontested" means there was never opposition to the issue. It does not include issues resolved by settlement or stipulation.

[8] Exhibit 1, pp. 4-5.

[9] Exhibit 77, p. 138.

sharply during the financial crisis. In December 2003, Standard & Poor's restored SCE's credit rating to BBB, which is an investment grade rating. In February 2005, Standard & Poors upgraded SCE's credit rating to BBB+. Moody's Investors Service (Moody's), a second major rating agency, also restored SCE to an investment grade rating. Moody's later upgraded SCE's credit rating to A3, equivalent to a Standard & Poors rating of A minus. According to Aglet, SCE has not shown that restoring its credit ratings to the A+ level is necessary for provision of safe, reliable service, or that additional revenues needed to achieve higher credit ratings are cost effective to ratepayers. Aglet also notes SCE's statement that financial recovery will be substantially complete if it achieves A minus ratings.[10]

In assessing SCE's finances, Moody's cites "[s]trong historical and projected financial credit metrics that reflect the collection of Procurement Related Obligations Account (PROACT) and the underlying financial strength of SCE's core utility business" and "continued evidence of a more constructive regulatory environment in California."[11] Moody's states that over the next several years "SCE's funds from operations (FFO) coverage of interest expense is expected to exceed 5 times."[12] Standard & Poors FFO interest coverage guidelines for A rated utilities with SCE's business profile of six indicate a range of 5.2x to 4.2x. Wall Street expects that SCE's FFO interest coverage will be stable and sound. Barron's, a publication that focuses on investment issues,

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[10] SCE, Hunt, 22 RT 2172-2173.

[11] Exhibit 409, pp. 50 and 57, November 25, 2003, and December 22, 2004.

[12] Exhibit 409, p. 57, December 22, 2004.

characterizes the stock of Edison International as having the prospect of market-level returns but with less risk than the broad market.

Aglet asserts that recent earnings by Edison International (EIX), SCE's holding company, are solid. The holding company was able to retire $571,000,000 of maturing debt in September 2004, which improved key credit quality measures, even after the company increased cash dividends to shareholders. SCE provides the lion's share of earnings, cash flows and dividends for Edison International.

Based on the above discussion, we believe that SCE has substantially recovered from the financial effects of the 2000-2001 energy crisis, and it is not necessary to factor in further financial recovery in resolving specific issues in this proceeding.[13]

2.3 Forecasting Issues

2.3.1. Averaging and Trending

As discussed in prior Commission decisions, there are a number of acceptable methodologies for forecasting test year costs.[14] In this GRC, parties have used averages and trends of recorded costs, the most recent recorded costs, as well as forecasts based on budgets or incremental budgets over recorded amounts. Depending on circumstances, one method may be more appropriate

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[13] In SCE's last GRC decision, D.04-07-022 at pp. 11-12, the Commission addressed restoration of investor confidence: "[W]e 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." Since that time, SCE's financial health has only improved.

than others. Under other circumstances, two or more methods may be equally appropriate. In general, the parties' testimony should explain (1) why its proposed methodology is appropriate, (2) why it is better than methodologies proposed by other parties and (3) why the results are reasonable. The Commission must weigh this information in deciding which methodology should be used and how it should be used.

We note that in using budget based methodologies, the forecasts are often based on incremental budgets over a base amount, usually the last recorded year. While this may be appropriate and reasonable in many instances, it is not a complete bottoms up budget and may be questioned, particularly as to what is already embedded in the historic data. While incremental budgets may capture anticipated increases over historic levels it is not always clear that (1) additional productivity from past or current projects are also being properly cast on a forward basis, (2) that certain historic costs will be necessary in future years and can, instead, be used to offset new costs, and (3) that the proposed budgeted costs are not included in another form in the embedded recorded data. When these types of issues are raised, the utility has the responsibility to demonstrate the reasonableness of its estimates, even if it means identifying and justifying all costs embedded in the base year amount.

2.3.2. Increased Costs of Providing Service

SCE has asked the Commission to authorize a revenue requirement commensurate with the company's cost to serve its customers. In many instances, SCE asserts that use of recorded data is inappropriate because of

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[14] For instance, *see* D.04-07-022, *mimeo.* at pp. 15-17.

changed circumstances. The company highlights three points to support its position.

- First, SCE's electric system was built largely in the decades after the Second World War, and many of its components are wearing out at the same time. SCE provided consultant testimony that assessed SCE's system and the capital investment required to slow its deterioration. SCE states this testimony was unchallenged by any party.
- Second, SCE asserts that its plan of stepped-up capital investment is the lowest cost option for its customers and that embracing deferred maintenance or a run-to-failure philosophy advocated by the DRA and seconded by other parties, will be more costly over time.
- Third, according to SCE, its workforce is rapidly aging, with the over-50 population having doubled since 1998, and DRA's proposals would guarantee widespread vacancies in the years to come. SCE also indicates that its request for salaries and benefits is validated by the Total Compensation Study developed by an independent third party in accordance with the Commission's guidelines, and jointly directed by DRA and SCE.

As a preliminary matter, we agree with many of the points raised by SCE. We supported the concept of the distribution capital replacement program in SCE's last GRC and do so again in today's decision. In deciding this case, we will consider the increased costs to customers if system components are allowed to run to failure. Also, we agree that there may be incremental costs related to adjusting to an aging workforce. Therefore, we do not necessarily rely on lower, recorded data to forecast expenses or capital expenditures. However,

we do not feel compelled to accept SCE's estimates either. SCE has the burden to show that, under these circumstances of an aging distribution system and an aging workforce, its forecasts of costs are fully justified and supported. If at any time we feel that burden had not been met, we will not hesitate to reduce SCE's request.

2.4. Joint Comparison Exhibit

Between SCE and the other participating parties, there are numerous conflicting estimates and recommendations. This is complicated by errata and stipulations that have occurred at different times during this proceeding.

The Joint Comparison Exhibit reconciles SCE's corrections, revisions and agreements since the filing of its application. Similarly, it reconciles changes to the estimates and recommendations of the interested parties since their initial submittal of testimony. The parties' final positions, prior to update testimony, are reflected in the Joint Comparison Exhibit, and the numerous resultant issues that are identified and summarized form the basis for determining what must be addressed and resolved in this decision. Revisions to SCE's request due to its agreement with the positions of other interested parties, as reflected in the Joint Comparison Exhibit, are reasonable. Those revisions, as well the adopted numbers related to the resolution of issues in this decision, are reflected in the results of operations model used to calculate the adopted summary of earnings table and related tables for this proceeding. Workpapers for the RO model were previously identified as late filed Exhibit 900 and are, at this time, received in evidence. Identified issues related to SCE's agreement with other parties' proposals are explained in the Joint Comparison Exhibit and will not be addressed further in this decision.

3. Differences in Expense Forecasts

Following are discussions of the issues related to expense forecasts, as identified in the Joint Comparison Exhibit. Differences relate to the Generation (or Production), Transmission and Distribution (T&D), Customer Accounts, Customer Service & Information (CSI), and Administrative & General (A&G) categories. Unless otherwise indicated, expenses discussed are in base year 2003 dollars. The adopted forecasts are incorporated in the development of the adopted expenses by FERC account, as detailed in Appendix C. Appendix C also details the escalation from base year 2003 dollars to test year 2006 nominal dollars.

4. Generation Expenses – Mohave Generating Station

Mohave was shut down at the end of 2005. The 1999 Mohave Consent Decree required installation of pollution-control equipment or the ceasing of operations using coal fuel in January 2006. At the time SCE filed this application, SCE did not know whether Mohave would operate in 2006. Therefore, SCE prepared three cases to bound the range of foreseeable outcomes: (1) continued operation of Mohave without a break in service, (2) temporary shutdown of Mohave to allow installation of required pollution control equipment, and (3) permanent shutdown of Mohave after December 31, 2005. SCE stated that once it became clear which case will occur, SCE would amend the filing to eliminate the other two cases.

4.1. SCE's Proposal

For its application filing, SCE used the continued operation scenario as the assumed outcome for its showing. Due to the uncertainty and difficulty in forecasting Mohave costs, SCE also requested two-way balancing account treatment. SCE would record its share of all Mohave costs in the balancing

account and all amounts in the balancing account would be subject to refund following reasonableness review.

In its September 26, 2005 update showing, the company asserts that continued operation remains the most appropriate scenario to use for the purpose of setting SCE's revenue requirement, even though uncertainty remains right now as to whether continued operation of Mohave will be achievable. Issues affecting Mohave's post-2005 coal supply (including slurry water supply) remain unresolved at present, and so the full range of Mohave outcomes still remain possible, from continued operation to permanent shutdown. Nevertheless, SCE contends that the Mohave co-owners and the other parties directly involved in Mohave's coal supply continue to pursue intensive negotiations, water studies, an environmental impact study and other related efforts to resolve the coal supply issues, and in SCE's view a successful resolution of all those issues remains possible. SCE states that achieving Mohave continued operations would mean important and valuable benefit to SCE's customers, in terms of both fuel diversity and reliability, especially in light of recent natural gas price increases.

SCE requests that the Commission, in setting the appropriate revenue requirement for Mohave, take into account the following considerations: (a) setting the revenue requirement based on the continued operation scenario represents a no-regret path, in which SCE has full latitude to pursue the possibility of continued Mohave operations, while SCE's customers remain protected from risk of unreasonable spending, and (b) setting the revenue requirements at any level other than the continued operation scenario could hamper the ongoing efforts by SCE and other relevant parties to resolve the

issues necessary to allow continued operations at Mohave for the benefit of SCE's customers.

4.2 DRA's Proposal

For ratemaking purposes, DRA considers a temporary shutdown to be the appropriate scenario. DRA states that a temporary shutdown is more probable, given the likelihood that capital expenditures and construction associated with the environmental upgrades will not be completed by January, 2006, as required pursuant to the 1999 Mohave Consent Decree. As noted in SCE's testimony, the 1999 Mohave Consent Decree requires the installation of pollution-control equipment, or the cessation of operations using coal fuel in January, 2006. DRA states that assuming the Consent Decree is enforced, temporary or permanent shutdown should occur in the test year, and continue throughout the effective rate period. DRA cites a California Energy Markets article from August 2004, which noted the following:

> Hence, even if the coal and water to run the plant past 2006 become available, the plant will have to be shut down while the environmental upgrades are made. SCE has said that could take until 2009 or 2010. (California Energy Markets, August 13, 2004, No. 784, p. 5.)

DRA recommends the Commission adopt the SCE's temporary shutdown scenario, with balancing account treatment.

4.3 TURN's Proposal

TURN's position is that the requirements of the Mohave Consent Decree clearly have not changed, and, as such, the plant must shut down after December 31, 2005. Given the unchanged circumstances, TURN recommends the Commission not authorize capital and Operation and Maintenance (O&M) spending as forecast in Edison's continued operations scenario.

TURN argues that SCE has not presented any new facts to support the idea that there will be a quick resolution of all the unresolved issues surrounding Mohave's continued operation (*e.g.*, coal supply, water supply, environmental impact study, and the pollution control equipment deadline). Also, the difficulties and uncertainties are substantial enough that SCE itself does not include Mohave as part of its resource portfolio or supply forecast after December 31, 2005.

TURN notes that while SCE has promised to return O&M expense money it does not actually spend on Mohave (through two-way balancing account treatment), it has made no promise that it would not spend money unnecessarily. Also, SCE's proposal would provide the Company with funds that it could spend on unnecessary expenses and unnecessary capital additions. TURN states that those capital additions could all be done at a later stage, when the future of the plant is more certain.

TURN recommends that the Commission:

- Find that the "continued operation" scenario is not credible as all evidence indicates that Mohave will shut down for some period of time at the end of 2005.
- Allow $10.110 million in capital additions forecast as part of the "interim shutdown" scenario in this rate case.
- Do not authorize the costs of any other capital projects in rates and evaluate those projects in (A).02-05-046 (the Mohave case), where they can be considered as part of the overall cost effectiveness of the plant and be included in the capital costs of the plant restart.
- Authorize a total Mohave O&M budget of $12 million (2003 dollars) for plant operations in 2006 (based on a rapid rampdown toward a much lower number of

employees to 70 FTE) and $6 million in 2007-2008 (50 FTE).

- Adopt two-way balancing account for the plant's O&M costs, if the number of staff is capped at 70 active FTE over 2006 and no more than 50 in 2007-2008.
- Allow existing net plant in rate base (as Plant Held for Future Use – PHFU), but do not allow any projects not used and useful before the end of 2005 into rates. All new capital additions should be capitalized as construction work in progress (CWIP) (Account 107) and should accrue allowance for funds used during construction (AFUDC). There should be no transfer of capital additions from CWIP to Property Held for Future Use until such time as the plant is used and useful for utility service.

4.4 Discussion

Of the three scenarios, temporary shutdown appears to be a reasonable approach at this time. The evidence indicates that continued operation will not happen, and Mohave will shut down for some period of time. Whether the shutdown will be permanent or temporary is not clear. Even if it is temporary, when it would restart is unknown. That would depend on how and how quickly SCE and the other relevant parties resolve the outstanding issues. We prefer to assume a temporary, rather than permanent, shutdown at this time, in case a return to operation is authorized at some time in the future. Depending on the circumstances, the continued operation or the temporary shutdown and return to operation of Mohave may provide significant benefits to SCE's customers. Implementation of a permanent shutdown scenario might preclude a return, or at best would likely preclude a timely return, to normal operation.

SCE has determined, and we will adopt, O&M expenses and capital related costs associated with a temporary shutdown scenario. In general, a

temporary shutdown of Mohave requires that plant equipment be reliably maintained in order to enable a return to normal operations. The adopted costs relate to a temporary shutdown as envisioned by SCE, whereby return to normal operations would be once the environmental controls have been installed. We note that if Mohave shuts down and then returns to normal operations, when and the circumstances under which that return happens may be different than what is assumed in this decision. For example, SCE may be able to negotiate further operation of Mohave prior to installation of environmental controls.

Due to the many uncertainties related to this issue, SCE's request to establish a two-way balancing account is reasonable and will be adopted. SCE shall record its share of all Mohave O&M and capital related costs in the balancing account. Temporary rate recovery will be provided by the associated O&M expenses and capital-related costs adopted by this decision. Permanent recovery of costs, which may be higher or lower than the level adopted by this decision, will be based on the results of a future reasonableness review. By application, SCE shall make an affirmative showing of reasonableness on the need for, and extent of, all costs recorded in the balancing account.

As a general matter, the adoption of a two-way balancing account, with reasonableness review, should mitigate SCE's concern that setting the revenue requirements at any level other than the continued operation scenario could hamper the ongoing efforts by SCE and other relevant parties to resolve the issues necessary to allow continued operations at Mohave for the benefit of SCE's customers. No matter what revenue requirement level is set, SCE will ultimately only receive rate recovery for those costs that the Commission determines are reasonable. The only difference is that the balancing account may

be over- or under-collected depending on what costs are included as part of this decision and what costs are ultimately found to be reasonable.

Rather than reducing the temporary shutdown scenario-related costs and imposing other conditions, as proposed by TURN, we are adopting the temporary shutdown costs projected by SCE and the two-way balancing account as proposed by SCE. Fine tuning the costs and procedures would be pointless unless we knew exactly when and under what conditions Mohave would return to operation. However, again, we are not prejudging the reasonableness of any of the costs. SCE must justify its actions in responding to whatever ultimately happens, whether it is continued operation, some form of temporary shutdown, or permanent shutdown. SCE must make a full reasonableness showing on its actions as well as on all costs booked to the two-way balancing account. Only costs found by the Commission to have been reasonably incurred will be permanently recovered in rates.

In summary the adopted Mohave O&M expenses for the test year, under the DRA supported temporary shutdown scenario, amount to $19,997,000 (SCE's share), as opposed to SCE's requested amount of $41,002,000 or TURN's recommended amount of $12,000,000. For 2005 and 2006, the adopted capital additions amount to $5,338,000 (SCE's share), as opposed to SCE's requested amount of $13,951,000 or TURN's recommended amount of approximately $1,100,000.[15]

[15] Approximation based on TURN's recommendation as modified in its opening brief.

5. Mohave Sulfur Credits

On January 11, 2006, the Just Transition Coalition (Coalition)[16] filed a petition to intervene in this proceeding. At the same time, the Coalition filed a Motion for a "Just Transition" in Response to the Closure of the Mohave Generating Station. The Coalition states that SCE's decision to close Mohave on December 31, 2005, requires the Commission to immediately consider and grant the Coalition's motion for a "Just Transition" for the Hopi Tribe and the Navajo Nation in response to that closure. The Coalition proposes a Just Transition Plan, the purpose of which is to allocate funds derived from the closure of Mohave to enable the Navajo and Hopi communities to invest in sustainable economic alternatives, including renewable energy options. According to the Coalition, the Just Transition Plan offers opportunities for the nations, ratepayers, and the environment to benefit by shifting from an older, dirty source of electricity to cleaner energy alternatives.

The Coalition proposes that a separate Mohave Just Transition Phase be instituted in this consolidated proceeding with a proposed schedule that includes a final Commission decision on either May 11, 2006 or June 15, 2006, depending on whether evidentiary hearings are required.

The Coalition requests that the Commission (1), direct and authorize SCE to create a new Mohave Sulfur Credit Sub-Account in its Energy Resource Recovery Account (ERRA) tariff and to separately track as a credit entry in that sub-account sales of SCE's sulfur allowances created by Mohave's closure,

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[16] The Coalition is composed of the following non-governmental organizations: Indigenous Environmental Network, Black Mesa Trust, Black Mesa Water Coalition, To' Nizhoni Ani, Grand Canyon Trust, and the Sierra Club.

effective December 31, 2005; (2) direct SCE to secure funds resulting from the sales credited to this new sub-account in an escrow account and to distribute those funds to the Hopi Tribe and the Navajo Nation upon receipt by SCE of annual investment plans adopted by a majority of Navajo Chapters in the Black Mesa Region and by a majority of all Hopi Villages that reflect priority conditions for the use of those funds; and (3) direct that such distributions by SCE be recorded as debit entries to the new Mohave Sulfur Credit Sub-Account and that this sub-account be continued in effect through 2026 when Mohave will otherwise stop operating due to loss of the plant's rights to use Colorado River water for generating electricity.

According to the Coalition, its request is an appropriate and timely response to SCE's decision to close Mohave and is urgently needed to make restitution to, and provide investment opportunities for, the Hopi Tribe and Navajo Nation to mitigate the adverse economic and social impacts of that closure upon these communities. Such restitution is further required to compensate the Hopi Tribe and Navajo Nation for subsidizing decades of coal mining and burning that has allowed SCE and its customers to benefit from a supply of cheap power from Mohave. Further, the relief requested by this motion will ensure that this "just transition" funding to the Hopi Tribe and Navajo Nation will continue until the end of Mohave's electric generating claims on Colorado River water in 2026.

Since the Motion might have been of interest to parties to the service list for the "Mohave" proceeding, A.02-05-046, which was closed with D.04-12-016, an ALJ ruling was issued on January 19, 2006 stating that any party wishing to respond to the Motion may do so in A.04-12-014/I.05-05-024 without filing a

motion to intervene. Responses to the Motion were due on January 27, 2006 and were filed by SCE, the Navajo Nation[17], the Hopi Tribe, DRA, and TURN.

Among other things, SCE states that the Motion is untimely; the ratemaking proposal is contrary to established Commission precedent which returns allowance proceeds to SCE's customers; the Motion is an attempt to relitigate issues already decided in SCE's favor; the Tribes' compensation under the coal leases has been fair and reasonable; and SCE intends that Mohave return to service. It is SCE's position that the Commission should deny the Motion summarily, without embarking on any of the six-month procedure proposed by the Coalition.

The Navajo Nation states that because it is doing all in its power to keep Mohave operational, the Commission should deny the Motion as premature or refrain from deliberating on it until the Mohave stakeholder negotiations[18] are concluded. It also noted that the Coalition is acting on behalf of small special interest groups, not the Navajo Nation or the Hopi Tribe.

The Hopi Tribe requests that the Commission adopt that portion of the Motion which requires SCE to track its sales of sulfur credits from Mohave, indicating that this step preserves the Commission's options to the extent that the current Mohave negotiations fail. The Hopi Tribe requests, however, that the

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[17] The Navajo Nation filed its response on January 20, 2006 accompanied by a petition to intervene.

[18] On March 4, 2004, SCE, the other Mohave co-owners, Peabody Coal, the Hopi Tribe, and the Navajo Nation signed a memorandum of understanding (MOU) whereby the parties agreed that SCE would fund a feasibility study to determine if the C-Aquifer would provide a suitable water source to supply the coal slurry process. In addition, the signatories to the MOU agreed to continue negotiations on water and coal issues. Negotiations are still ongoing.

Commission postpone any decision regarding the disposition, timing and amount of any payments of sulfur credits to the Tribes as just compensation for Mohave's closure, until such time as the parties involved in the current negotiations advise the Commission regarding the outcome of such negotiations. The Hopi Tribe also recommends that the Commission give further consideration to the question of the proper forum for consideration of the Motion, noting there are several outstanding Mohave issues, including this motion, the Mohave Alternative/Complementary Study, the continuing Mohave negotiations, and certain requests made by Edison relating to Mohave. It may make sense to consider all of these issues in a separate or sub-docket.

DRA agrees that SCE should track sales and revenues, if there are any, associated with sulfur allowances that may ultimately be recovered through the closure of the Mohave plant. However, it is DRA's position that any revenues that may ultimately be generated by sulfur allowances created by Mohave's closure should flow directly to ratepayers. DRA also states that if the Commission is inclined to consider the Coalition's request, then the merits of the proposal should be subject to a full hearing process in an appropriate forum after it is determined that such sulfur allowances are actually being generated on a permanent basis by Mohave's closure. Also, all interested parties should be provided with notice and an ample opportunity to address the issues related to the request; and such a process should be developed only after the Commission makes a determination that the Mohave facility will be permanently shutdown.

TURN offers general support for the Motion subject to several clarifications. According to TURN, the Commission should approve the Coalition request to establish an ERRA sub-account both to formalize the practice of having such revenues returned to customers, and to enable tracking of funds

available for alternative economic development on tribal lands. However, TURN is concerned that the Motion does not adequately explain the process for disbursing funds from this memorandum account, and could even be read to imply that there would be no Commission review and approval of any such awards. Given the potential magnitude of ratepayer funds tracked by this account, TURN recommends that the Commission should review, circulate for public comment, and ultimately approve any proposals which would involve financial disbursements. TURN also recommends that priority be given to any investment plan which would provide benefits both to the Tribes and to California ratepayers and expressed its interest in participating in the development of guidelines governing the eligibility of tribal investment plans and the evaluation criteria which would be applied to determine funding awards.

The Coalition filed its reply on February 3, 2006. It is the Coalition's position that none of the arguments offered in opposition to the Motion have merit, and both the Motion and the Coalition's petition for leave to intervene in this proceeding should be granted promptly by the Commission. The Coalition notes that while SCE, the Navajo Nation, and DRA oppose the Motion in whole or part, the responses of TURN and the Hopi Tribe, which reflect a better understanding and appreciation of the intent and merits of the Motion, support its core requested relief with recommended conditions or refinements.

Furthermore, the Coalition believes that TURN's recommendations have merit and should be incorporated in the process and schedule proposed by the Coalition in its motion. For this reason, the Coalition has amended its requested relief to incorporate, in particular, the development of guidelines to be applied to any investment plan by which funds from the Mohave Sulfur Credit

Sub-Account are to be distributed and to ensure ongoing Commission oversight of this sub-account and revenue distribution.

5.1 Discussion

According to the Coalition, sale of the Mohave sulfur credits would yield approximately $65,000,000 annually, of which SCE would receive 56% based on its ownership share. The amount of money potentially at stake is therefore substantial. Whether such funds should be credited to SCE's ratepayers, used to fund the Coalition's proposed Just Transition Plan, or disbursed in some other manner is a matter that must be considered carefully. We feel such consideration to be premature at this time. As pointed out in responses to the motion, the future operating status of Mohave is not known. SCE states that it intends that Mohave would return to service. However, SCE and the other Mohave co-owners have not yet been able to reasonably commit to the large investments required for the pollution controls, because of critical issues impacting Mohave's post-2005 supply of coal and, especially, slurry water. Mohave co-owners, the Hopi Tribe and the Navajo Nation, Peabody and others -- have been engaged in prolonged and intensive efforts to resolve the Mohave water and coal issues so as to allow the Mohave pollution controls to go forward. Such efforts are still continuing among them now and are summarized every month in the Mohave monthly status reports that SCE serves on the Commission's Energy Division and on the service list for the Mohave proceeding, A.02-05-046, which is now a sub-service list within R.04-04-003.[19]

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[19] Ordering Paragraph 4 states, "Edison is to file monthly reports with the Commission's Energy Division updating any progress made on the coal and water negotiations, the C-Aquifer studies, the alternatives' investigation and shortening the Gantt Chart time-line."

The long term effects on ratepayers as well as the Hopi Tribe and the Navajo Nation will vary depending on whether Mohave returns to service or is permanently shut down. We prefer to decide this issue when the future operating status of Mohave is more certain. We therefore deny that part of the Coalition's motion that would expeditiously decide, as part of this consolidated proceeding, if and how proceeds from the sale of sulfur credits would be distributed to the Hopi Tribe and Navajo Nation. We will preserve the Coalition's rights for consideration of this part of its motion by granting the part of the motion that would establish an ERRA sub-account to accumulate revenues from the sale of any sulfur credits created by the December 31, 2005 Mohave closure. Funds should not be disbursed from this sub-account without specific Commission authorization to do so.

With respect to where the Coalition's proposal for disbursement of funds should be addressed, Ordering Paragraph 9 of D.04-12-016[20] states, "Edison is to prepare an application for authorization to go forward with the environmental retrofits and other capital expenditures, with the costs for water, coal and other environmental controls, so once the water and coal issues are resolved, Edison can file the application forthwith. Capital costs found reasonable in this decision will not be re-litigated." If Mohave is to return to service, the issue of the distribution of revenues from the sale of Mohave sulfur credits should be addressed as part of that SCE application and litigated in that proceeding. If Mohave is shut down or a resolution of the future operating status is delayed, SCE should file an application, no later than January 1, 2007,

[20] Issued in the Mohave proceeding, A.02-05-046.

for authority to disburse funds accumulated in the Mohave sulfur credit sub-account along with a proposal for such disbursement.

6. Generation Expenses – Four Corners Generating Station

SCE requests that the Commission authorize SCE to file a "Variable Overhaul Outage Schedule" advice letter for the Four Corners Generating Station (Four Corners), which would be part of the Post-Test Year Ratemaking advice letter, to enable SCE to recover the O&M expenses associated with the Unit 5 overhaul. This mechanism is similar to that used for nuclear refueling outages. SCE believes this mechanism will enable appropriate maintenance of Four Corners to be conducted while allowing SCE to recover the expenses associated with that overhaul when they actually occur. The forecasted cost is $4,580,000 and includes incremental costs for overhaul of the turbine/generator, scaffolding, inspecting and repairing the Unit 5 boiler, and overhauling other plant equipment.

Aglet opposes the request, indicating there is no Commission precedent for such adjustments at fossil plants. Also, the amount at issue is not large. Aglet states the scale and timing of overhaul costs at one coal plant do not justify a new mechanism that would shift risks to ratepayers without any offsetting benefit.

6.1 Discussion

While a similar mechanism has been established for the SONGS related refueling outages, the forecasted costs of those outages are approximately 10 times the estimated cost of the Four Corners overhaul. The amount of money at risk related to the anticipated 2008 outage at Four Corners does not justify establishing a new ratemaking mechanism. We will therefore deny SCE's request to do so.

Our action however may result in SCE not recovering outage costs that are anticipated in 2008. In forecasting test year expenses, SCE adjusted recorded expenses to exclude past overhaul costs. Therefore, consideration of overhaul costs is not reflected in SCE's test year forecasts for Four Corners. Extension of the test year level through post-test year 2008, as proposed by SCE and adopted by this decision, will result in no specific recovery for the overhaul. It is not clear how Four Corners outage costs have been accounted for in the past. However, SCE owns a share of two units and the outages occur on an approximate six-year cycle. It would be reasonable to assume one overhaul will occur during this three-year rate case cycle. We will therefore spread the forecasted cost of the anticipated 2008 overhaul, which amounts to $4,580,000, over the three year GRC cycle to normalize the anticipated cost. The adopted expenses for Four Corners are increased by $1,526,000 over the unopposed test year level proposed by SCE. Absent detail on overhaul accounting, that amount will be split evenly between Accounts 512 and 513.

7. Generation Expenses - SONGS

7.1 Aging Workforce

SCE's Test Year 2006 forecast of SONGS O&M costs includes an adjustment to provide additional staffing needed in advance of an anticipated large number of retirements caused by the aging of its SONGS 2 & 3 workforce. The adjustment is reflected (SCE's share) in Account 517 ($296,000), Account 520 ($319,000), Account 524 ($1,423,000), and Account 528 ($2,390,000). SCE projects that personnel retirements will increase for SONGS 2 & 3 in several job classifications that will require a lengthy period of training and qualification before individuals are allowed to perform their duties. In some cases, this training lasts as long as three years. According to SCE, these new hires will

replace an increasing number of employees expected to retire from job classifications between 2004 and 2008.

SCE states that it developed the forecasted hiring of new employees in 2006 by comparing the age and length of service of the SONGS 2 & 3 existing workforce for each year from 2004 to 2008 to the historical average age and length of service of employees at retirement, for each job classification. This comparison produced an estimate of the number of employees expected to retire in each job classification each year through 2008. SCE subtracted the historical retirements from estimated expected retirements. This produced the forecast number of employees in each job.

DRA opposes SCE's aging workforce adjustment for SONGS. DRA states that SCE has been preparing for the 2004 retirement bubble since the 2001/2002 timeframe. DRA considers these preparation costs, especially for 2003, historically embedded. Further, in preparing for the 2005 and 2006 retirement bubbles, a portion of the costs should have been incurred in 2002 and 2003, and again are historically captured. Since it believes that the impacts of an aging workforce have already been embedded in SCE's base forecast, DRA recommends the Commission disallow the $5,900,000 incremental increase request for test year 2006.

In response to DRA' recommendation, SCE states DRA errs in claiming that costs associated with the retirement bubble are already embedded in base forecasts. SCE states that it removed 2003 recorded aging workforce costs of $1,500,000 (100% level) when deriving the incremental aging workforce replacement costs of $5,900,000 (100% level) for test year 2006.

7.2 Discussion

It appears that SCE did remove prior aging workforce costs from the recorded data prior to estimating and including test year 2006 aging workforce costs. While there is no double counting, SCE's forecasted level of test year aging workforce costs is questionable.

For example, regarding Health Physics (HP) Technicians, SCE states "Retirements of HP Techs average 1 employee per year at age 52. Based on this historical data, an additional 10 employees will reach the age of 52 and retire by year-end 2008. HP Tech qualification and training takes three-years. SONGS 2 & 3 will hire and begin training 10 HP Techs in October 2005. These additional employees will begin filling Retirement Bubble vacancies in September of 2008."[21]

SCE's explanation is incomplete. There is no mention of how many employees who were 52 or older did not retire historically. Just because, on average, one employee, at the age of 52, retires each year, it does not necessarily mean ten employees will retire if ten employees reach the age of 52. If 52 were the maximum retirement age, or if some other reason employees all retired at age 52, it would be reasonable to assume the 10 employees would retire, if they were projected to reach age 52 during the relevant timeframe. However, more than likely, employees at ages more and less than 52 retire, and on average one employee with an average age of 52 retires each year. It does not appear that SCE takes into consideration that, of the employees who reach the age of 52, some may not retire until they are older than 52. Under these circumstances, where 52 is a fairly young age for retirement, more information is needed. For

example, if there were an average of 4 employees at age 52 or older who did not retire historically, it would indicate that only 20% of those in that age category retire. The addition of 10 employees to that age category would likely result in two additional rather than 10 additional retirements.

On the other hand, retirements for test technicians averaged 0.8 technicians per year at an average age of 61. Retirement at 61, average age or otherwise, is more likely than at 52. We would expect a higher percentage of retirements as additional employees reached that average retirement age. Even so, our concerns regarding SCE's estimating methodology, as expressed above for HP Techs prevent us from concluding that SCE's estimate of the number of employees that will retire is reasonable. This concern relates to all nuclear positions affected by the retirement bubble.

Clearly SCE's nuclear related workforce is aging. However, based on our concerns, as discussed above, we are reluctant to adopt SCE's requested increase. Instead, we will reflect an incremental increase equal to 50% of SCE's request -- $2,950,000 (100% level) or $2,212,000 (SCE share). Since the 50% adjustment is an approximation, it will be applied equally to all affected accounts.

7.3 Account 532 – SONGS 2&3 Site Projects Estimating Methodology

SCE recovers costs of SONGS 2&3 work scope occurring on a cyclical basis or requiring special focus in the Site Projects Functional Group. The majority of the activities are O&M projects developed in response to action requests or to external events or requirements. The number and scope of the

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[21] SCE, Exhibit 6, p. 22.

projects and efforts vary from year to year. SCE's estimate for these projects is based on the 2003 recorded amount plus an adjustment to recognize the Used Fuel Transfer Project as being a new and unique project. On a 100% basis, SCE estimates the cost of the fuel transfer project to be $1,700,000 per year over the three-year GRC cycle.

DRA used a three-year average and did not include the Used Fuel Transfer Project as a separate adjustment. DRA argues instead that, given the varying nature of projects, cost estimates, operation alterations, and the potential for project scheduling adjustments, to identify a single project for exclusivity distorts a fair comparison. DRA considers the use of "pure" averaging a better approach to account for these varying fluctuations.

7.4 Discussion

In rebuttal testimony, SCE accepted DRA's use of a three-year average instead of its proposed 2003 recorded amount. However, SCE continues to argue that the cost of the Used Fuel Transfer Project, a new and unique project, should be recognized, in addition to the averaged amount.

We will use the three-year average as a base for forecasting the site projects. Regarding the fuel transfer project, under the justification for this project, SCE states:

> "After the removal of Unit 1 used fuel from the SONGS 2&3 fuel pools in 2003 and 2005, capacity of the SONGS 2&3 used fuel pools will again be reached by 2007, which will prevent the capability to perform full core offloads during the refueling. The capacity to perform full core offloads is necessary for certain maintenance and inspections of the plant. SCE must continue to remove used fuel from the used fuel pools in

> order to maintain full core off load capability with a prudent amount of schedule contingency, and thus enable continued reliable generation of electricity."[22]

The Used Fuel Transfer Project, while necessary, does not appear to encompass new and unique activities. Such activities were performed in conjunction with SONGS 1. However, the removal of SONGS 1 used fuel was funded through SONGS 1 shutdown O&M expenses. The related activities for SONGS 2&3 are new and have not previously been reflected in expenses for SONGS 2&3. The three-year average will cover the types of projects that were incurred, or are similar and related to projects that were incurred, during that timeframe. However, the SONGS 2&3 fuel transfer project is a sufficiently new, unique, annually recurring cost such that it is not covered by a three-year average of historic site expenses. SCE's request to recover the used fuel transfer project incrementally to the three-year average of historic site projects is reasonable and will be adopted.

7.5 Account 517 – Nuclear Energy Institute Funding

SCE records annual Nuclear Energy Institute (NEI) dues in Account 517, as non-labor. The forecast for 2006 is $652,000 (100% level), based on the 2003 recorded amount. SCE states that NEI is the nuclear energy industry's Washington, D.C.-based policy organization and that participation in NEI's programs, committees, and activities helps to address and resolve issues important to the nuclear energy industry.

TURN recommends disallowing 50% of the forecast dues because the organization engages in significant public relations, public advocacy and image

[22] SCE, Exhibit 91, p. B-2

advertising work. At present, legislative lobbying is undertaken with dues money collected in the past, but TURN maintains that NEI is a highly political organization with goals of encouraging the future development of nuclear energy and ratepayers should not be forced to subsidize political advocacy with which they do not agree.

7.6 Discussion

NEI explains its mission as follows:

> "**Mission**. The Nuclear Energy Institute is the policy organization of the nuclear energy and technologies industry and participates in both the national and global policy-making process. NEI's objective is to ensure the formation of policies that promote the beneficial uses of nuclear energy and technologies in the United States and around the world."[23]

The principal focus of NEI appears to be the advocacy of nuclear power, both nationally and globally. There are many aspects of such furtherance of the nuclear industry that may not be appropriate for ratepayer funding. SCE's direct and rebuttal testimonies do not provide information on specific activities and related benefits that accrue to the company and/or ratepayers. TURN however states that some of NEI's activities are related to work by nuclear owners to reduce costs or improve performance through work with the government and analysis of improving technologies. For this reason TURN recommends disallowing half, rather than all, of the NEI dues. We agree with TURN's characterization of the NEI and, absent any better analyses, adopt its recommended disallowance $326,000 (100% level).

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[23] TURN, Exhibit 356, p. 32.

SCE argues (1) there is no difference between lobbying and public policy advocacy, (2) all such costs are included in lobbying, and (3) all such costs have been excluded from its estimates. That this is the case is not at all clear. By its mission statement, public policy advocacy is the primary focus of the NEI. It would follow that public policy advocacy should then reflect a large portion of NEI's costs. However, SCE's estimated share of lobbying expenses was zero in 1999 and $91,000 in 2000.[24] We are not convinced that all public policy advocacy costs are reflected as lobbying and excluded from SCE's forecast. For ratepayer recovery of NEI dues, in the future, SCE should provide more detailed descriptions of the activities, the associated costs, and the resulting company and ratepayer benefits. With that information, in the future, we can make a more informed decision regarding disallowances.

7.7 SONGS Refueling and Maintenance Outage Expense

7.7.1. Flexible Outage Schedule Mechanism

SCE requests that the Commission establish a forecast cost for its refueling and maintenance outage costs of $61,200,000 at the 100% level ($45,900,000, SCE share) per outage per unit. SCE forecasts two outages in TY 2006. However, since it is difficult to predict with certainty for SONGS 2 & 3 whether there will be zero, one, or two outages several years into the future, SCE requests that the Commission continue to utilize a flexible outage schedule mechanism for the post-test years, like that adopted and affirmed in its decision on SCE's last GRC, D.04-07-022. The post-test year flexible outage schedule mechanism establishes a standard per unit per outage cost in the GRC and then

[24] SCE, Exhibit 91, p. D-2.

allows determination of whether zero, one, or two outages will occur in 2007 and/or 2008 through the flexible outage schedule mechanism to most accurately predict post-test year costs.

SCE's request for a flexible outage schedule mechanism for the post-test years is reasonable, unopposed and will be adopted. The outage cost reflects core and one-time activities, both of which are in dispute. The adopted cost per outage of $56,060,000 (100% level) is discussed below.

7.7.2. Refueling Outage – Core Costs

SCE developed its Test Year 2006 refueling outage forecast, at the 100% level, in two parts: (1) core outage activities for $50,940,000 and (2) one-time outage activities for $10,250,000. In making its forecast, SCE considered costs of six refueling outages (actual costs for SONGS 2 & 3 Fuel Cycle 11, SONGS 2 & 3 Fuel Cycle 12, and SONGS 2 Fuel Cycle 13 and estimated costs for SONGS 3 Fuel Cycle 13) to develop its refueling outage costs.

For estimating the refueling outage core costs, SCE averaged typical core costs for the recorded five refueling outages. Additionally, SCE proposed three adjustments by (1) adding a non labor escalation premium of $3,300,000, (2) adding a Bechtel supplemental labor contract change of $750,000, and (3) reflecting a $3,800,000 credit due to a change in capitalization criteria.

Aglet proposes removal of the non-labor escalation premium because SCE has not provided adequate justification. SCE criticizes the adjustment because Aglet singled out the one adjustment. SCE claims it provided the same level of detail for all three adjustments.

7.7.3. Discussion

We will adopt Aglet's recommendation to exclude the non labor escalation premium, because SCE did not meet its burden to justify the request.

Other than identifying the adjustment, SCE's testimony provides no information to support the need or calculation. To ignore the issue, as SCE suggests, only because there may be other unsupported costs as well is not a viable option. As stated in our preliminary discussion, SCE has the burden to affirmatively establish the reasonableness of all aspects of its application. Based on the record, SCE's request for a non-labor escalation premium is unsupported and will be disallowed

SCE's claim that both the Bechtel supplemental labor contract change and the credit to reflect a change in capitalization criteria have support similar to the non labor escalation premium needs to be addressed also. These two adjustments are similarly unsupported and, in principle, should be disallowed. To remove the Bechtel adjustment of $750,000 is straight forward and we reflect its removal in this decision. Regarding the $3,800,000 credit to reflect a capitalization criteria accounting change, we could merely reverse the accounting, that is increase expense by $3,800,000 and decrease capital by $3,800,000 assuming that there was an increase to capital because of this adjustment. Whether this would be correct is unknown, because the adjustment is not explained. Another option, since there is no support, would be to exclude the $3,800,000 entirely, that is, remove it from expense as proposed by SCE and assume there was an increase of $3,800,000 to capital and exclude that amount also. However, this appears harsh considering that the adjustment is an accounting change and presumably is not a request for money to fund additional activities. Since it is only an accounting change, we will instead leave the adjustment as proposed by SCE, that is reduce expense by $3,800,000 and assume capital has been increased by a like amount.

Exclusion of SCE's proposed non labor escalation premium and Bechtel supplemental labor contract change results in our adopted forecast of core costs of $46,890,000 (100% level).

7.7.4. Refueling Outage – One-Time Activities

For estimating the refueling outage one-time activities, SCE averaged the one-time costs for the five recorded outages and the forecasted one-time costs associated with the SONGS 3 Fuel Cycle 13 outage.

Aglet proposed to reduce SCE's average of one-time outage activities by $1,082,000. Aglet removed the costs to repair of the Unit 3 main generator rotor, amounting to $6,490,000, from the average arguing that it is an outlier. This forecasted item was the highest cost activity considered in the averaging of one-time activities.

SCE argues that other high cost activities will likely occur during 2006-2008. SCE states that it normalizes peaks and valleys that routinely occur between refueling outages by averaging both core and one-time activities, and Aglet's proposal to remove the peak cost skews the average.

7.7.5. Discussion

We note that in the average to determine one-time activities, there are already a number of significant one-time costs in the recorded data for the five completed refueling outages. Typical one-time activities will be reflected in the forecast of outages performed during this GRC cycle. The main generator rotor repair is however almost twice as large as any of the other adjustments. It is also a forecast for 2005, not a recorded amount. Since it is forecasted, there is some uncertainty as to whether the activity will actually be done in the timeframe suggested by SCE or whether SCE's cost forecast is accurate. For these reasons, we will not reflect the main generator repair in the average to

determine one-time activities for this GRC cycle. However, if the activity is actually performed, the recorded amount can be used in the averages to determine one-time activities in future GRCs. The adopted forecast for one-time activities is therefore $9,170,000 (100% level).

7.8 Allocation of SONGS 2 & 3 Costs to SDG&E

SDG&E owns a 20% interest in SONGS. Under the operating agreement between SCE and SDG&E, as the operator, SCE bills SDG&E for SDG&E's proportionate share of the actual total costs incurred by SCE in operating the plant, plus contractual overheads. The Commission has consistently used SCE general rate cases to determine the revenue requirement that SDG&E may charge its customers related to its share of SONGS billed by SCE (exclusive of fuel costs).[25]

In this proceeding, SDG&E has provided testimony that addresses the calculations and methodology for deriving its allocated share of SONGS costs. SDG&E points out that some of the costs that are allocable to SDG&E are found outside the SONGS portion of SCE's Results of Operations model. There are three principal groups of costs in this category. First, there are

[25] SDG&E also incurs some costs associated with SONGS directly, rather than having them billed to SDG&E by SCE. These directly-incurred costs are considerably less than the SCE-billed costs. SDG&E's directly-incurred costs are litigated in SDG&E's own general rate cases, because they do not overlap the subject matter in SCE general rate cases in the same way that costs billed by SCE to SDG&E for SONGS overlap the issues in SCE general rate cases. SDG&E's directly-incurred SONGS costs, therefore, are beyond the scope of this application. They were last forecast by the Commission in SDG&E's last "cost of service" case (A.02-12-028 decided in D.04-12-015) and will continue to be reflected in SDG&E's rates per decisions in that application until SDG&E's next GRC is decided.

SONGS-related SCE shared services billed to SDG&E. Second, there are Results Sharing costs, which are SONGS-related incentive compensation (for SCE employees) billed to SDG&E. Third, there are contractual overheads, which are SCE-applied loaders for SONGS-related A&G, Pension & Benefits and Payroll Tax allocated to SDG&E.

Assuming SCE's requested overall revenue requirements, SDG&E calculates its 2006 SONGS revenue requirement (exclusive of refueling outage O&M, directly incurred SDG&E costs, and fuel) to be $94,000,000 (2006 dollars), its revenue requirement per SONGS refueling outage to be $15,400,000 (2006), and its share of SONGS capital expenditures to be $25,600,000 for 2006, $21,000,000 for 2007, and $16,700,000 for 2008. SDG&E acknowledges its SONGS revenue requirement will differ from these numbers to the extent that the Commission adopts related costs other that those requested by SCE.

No party has challenged SDG&E's methodology for calculating its SONGS related revenue requirement based on costs allocated by SCE. It is reasonable, and we will use it to calculate SDG&E's share of SONGS related costs in this proceeding.

Based on the costs adopted by this decision, SDG&E's share of SONGS related costs are as follows:

2006 SONGS Revenue Requirement (2006 dollars)	
O&M	$83,300,000
Depreciation	2,800,000
Taxes other than on Income	200,000
Income Taxes	1,500,000
Return	3,800,000
Revenue Requirement	91,600,000
Rate Base	45,800,000
Rate of Return	8.23%[26]

7.9 Design Basis Threat Costs for SDG&E

D.04-12-015 (the decision in the 2004 base margin phase of SDG&E's last cost of service application) authorized recovery by SDG&E of Nuclear Regulatory Commission (NRC) Design Basis Threat (DBT) costs of up to $14,469,000 of 2004 capital expenditures and $760,000 of O&M expenses, subject to a one-way balancing account (the SDG&E Security Costs Balancing Account) until there was a review of the costs in a future Commission proceeding. D.04-12-015 stated that this review could occur in an SCE proceeding.[27] SDG&E has

[26] Rate of Return authorized for SDG&E in D.05-12-043.

[27] D.04-12-015, *mimeo.,* pp. 28-30.

provided information on DBT costs in this proceeding and requests that the Commission include a finding that SDG&E has made the showing required by D.04-12-015, and conclude the amounts authorized by D.04-12-015 should no longer be subject to refund.

In D.04-12-015, it was stated that before final recovery of DBT O&M and capital expenditures would be authorized, "SDG&E must make a clear and complete showing that (1) the recorded costs are attributable solely to new security activities and investments that are required by the April 29, 2003 NRC orders; (2) the recorded costs are truly incremental, *i.e.,* they are not included in this Phase 1 decision; (3) if any current (*i.e.,* included in this proceeding) security activities or planned investments are supplanted by compliance with the new NRC requirements, so that costs for those activities and investments are reduced, such cost reduction are properly accounted for; (4) the costs must be incurred by SDG&E and the other plant owners, and not by taxpayers; and (5) the recorded costs are otherwise reasonable."[28] SDG&E provided the following information and facts, which were not disputed by any of the parties to this proceeding:

- In this proceeding, SCE provided testimony on both O&M and capital expenditures related to the new security requirements. In Exhibit 13, SCE describes Work Order No. 1809-0509 as the capital project that satisfies the requirements of the April 29, 2003, NRC DBT order and subsequent guidance provided by the NRC. SDG&E's share was $15.0 million for 2004 and $1.1 million for 2005 (year-to-date through March). In Exhibit 8, SCE describes Adjustment #41 related to the increased O&M expense necessary to comply with the NRC security requirements. The related

[28] *Id.*

costs at 100% (excluding overheads) for 2004, 2005, and 2006 are $4.5 million, $9.8 million and $9.8 million in 2003. SDG&E's share of O&M expenditures (including overheads), are $2.5 million for 2004 and $1.1 million for 2005 (year-to-date through March).

- The incremental costs are not included in the SDG&E Cost of Service Phase I decision as SONGS O&M or capital expenditures. The incremental costs were separately identified and tracked in the SDG&E SONGS Security Costs Balancing Account.
- SCE in its Adjustment #41 "Increased Security to Comply with NRC Requirements," identified the changes to the forecast years 2004-2006 from 2003 to reflect the O&M expenditures of the SONGS Security Division necessary to comply with all existing NRC security orders. In its forecast, SCE identified costs that would decrease from the 2003 recorded level and included that decrease in its 2006 estimate.
- SCE's response to Data Request DR-ORA-180 supports the assertion that the costs have been incurred by SDG&E and the other plant owners, and not by taxpayers. In that Data Request, SCE was requested to answer the following questions: "a) advise whether recovery of a portion of security costs, via outside entities (*e.g.*, Homeland Security), were available to SCE. Did SCE receive or expect to receive any recovery for security costs from outside sources? b) In response to a) above, if no recovery was available, advise why no recovery was unable given SONG[S]'s potential as a target." SCE responded as follows: "(a) There are no available sources of funding from the federal government or other outside entities for SCE to recover all or a portion of the increased security costs to comply with NRC security requirements resulting from the September 11, 2001 terrorist attack. SCE has not received any funding or notice of proposed funding

from the federal government or other outside entities. (b) The Department of Homeland Security has distributed some first responder grants to state and local governments to supplement local funds, but to-date no such funding has been made available to public utilities….To date, no sources of funding have been available for the nuclear industry, including SONGS 2&3, to recover all or portion of the increased security costs to comply with NRC security requirements."

- SDG&E's share of DBT O&M and capital costs have exceeded the amounts initially estimated in A.02-12-028 and authorized in D.04-12-015. SDG&E's capital expenditures and O&M expenses exceeded the amounts authorized for 2004 and 2005 and thus no portion of these costs need to be refunded to SDG&E's ratepayers.

SDG&E's showing on DBT costs conforms to the specifications of D.04-12-015 and is reasonable. SCE's request that the amounts authorized by D.04-12-015 should no longer be subject to refund is unopposed and is granted.

8. Generation Expenses – Project Development Division

8.1 SCE's Proposal

For the test year, SCE requests $4,950,000 in expenses to fund its Project Development Division (PDD). Costs are included in Accounts 506 and 549. According to SCE, the PDD's primary function is to analyze, develop, and propose for Commission approval, cost-effective, utility-owned generation opportunities consistent with SCE's long-term procurement plan. These opportunities could include new plant construction, repowering, joint-ventures, purchasing shares in new or existing facilities, or other commercial arrangements. SCE states that secondarily, PDD provides the Resource Planning and Strategy organization with data regarding construction costs, project

economics and the commercial feasibility of future resource supply levels, as requested, to assist in long-term procurement forecasting. SCE lists PDD's activities to include the following:

- Identifying sites with the potential for development and construction of new utility-owned power generation projects;
- Conducting financial analyses and commercial evaluation of generation development opportunities and alternatives;
- Overseeing preliminary project engineering, permitting, and contract negotiations for potentially feasible projects;
- Managing regulatory approval processes at the California Energy Commission, California Public Utilities Commission, Federal Energy Regulatory Commission, and other state and local agencies;
- Developing and implementing plans to advance projects from the development phase to the construction and operations phase; and
- Providing ongoing support to resolve development-related financial, permitting, and contractual issues that may arise during construction or operations.

8.2. Positions and Other Parties

DRA opposes allowing SCE to recover the costs of this new Project Development Group as continuing expenses in base rates. DRA does not object to electric utilities owning generation or even procuring new "owned" generation, provided such ownership and development is on a level playing field with other generation developers. Ratepayer funding of personnel and contractor costs would essentially allow SCE a ratepayer-funded subsidy not available to any other entity seeking to develop additional generation.

Aglet states that allowing SCE to recover project development costs in base rates, while independent power project developers include such costs in their bids, would give SCE an unfair advantage in competition for future electric resources and could lead to higher rates for SCE ratepayers. Aglet recommends that, as a matter of public policy, the Commission must keep project development costs out of base rates -- specifically, SCE should record PDD costs "below the line" and include them in future resource bids as it chooses.

WPTF also states that it does not oppose the utility's proposal for creation of a PDD, indicating that, to the extent the utility decides that it wishes to engage in project development in the future, it will need to have personnel who are tasked with developing such options. However, WPTF recommends that the Commission should reject the SCE funding proposal for the PDD for the following reasons:

- First, the Commission has stated that it wishes to foster fair competition between utility-sponsored, turnkey, or buyout proposals and third party generation power purchase agreements (PPAs). It would be highly inconsistent with that vision to permit utility project development efforts to be subsidized with ratepayer dollars. To the extent the project development costs were not included in SCE's bids, RFO results would be inappropriately skewed in favor of the utility.
- Second, this action would be in direct opposition to the Long-Term Procurement Plan decision that the Commission issued on December 16, 2004. That decision, D.04-12-048, specified that a utility would only be able to recover from ratepayers the amount of the utility's bid, should it win the bid.

WPTF recommends that, should SCE elect to establish a PDD, it should be specifically required to include in the costs of each of its bids all PDD

costs associated with the development of the project that is being proposed by the utility; and SCE shareholders, rather than its ratepayers, should be solely responsible for any expenditure incurred by the PDD to develop projects that do not win a bid.

IEPA argues that the proposed PDD harms ratepayers in at least two ways. First, it undermines competition among project proponents that the Commission articulated as the model for utility procurement in D.04-12-048. Second, by requiring ratepayers to subsidize the development costs of only one of the competing project developers (*i.e.,* SCE), the PDD proposal directly increases the ratepayers' costs of generation. IEPA urges the Commission to deny SCE's request to establish a PDD at ratepayers' expense.

IEPA referred extensively to D.04-12-048, indicating the Commission repeatedly endorsed "an open, transparent and competitive bidding process" and "greater head-to-head competition." IEPA asserts that SCE should face the same cost risks as independent generators and developers to the extent that it engages in the project development business. Otherwise, the utility will not only have an unfair competitive advantage over independent generators and developers, it will also have no incentive to manage such costs prudently. As a result, SCE's ratepayers could end up paying far more for the development of new generation than they would otherwise. IEPA also states that, if the PDD proposal is approved, independent power producers will see how the utilities are allowed to recover project development and other costs from ratepayers outside of the solicitation process, and may become discouraged by such an unfair process and decide to invest in generation elsewhere, resulting in a less competitive generation market in California.

8.3 SCE's Response

SCE notes that its PDD request is less than half of 1% of its total test year request. SCE states this is a modest ratepayer investment in a program designed to protect SCE's ratepayers against market abuse by electricity suppliers. SCE explains that a PDD will provide such insurance to ratepayers by keeping open the option of utility-built generation. Such utility-built generation will provide the Commission with a Commission regulated option for development of utility-owned cost-of-service generation. SCE states that this option is necessary so that SCE and ratepayers are not forced to rely on the hope that independent generators will make their supplies available in the market. SCE notes that Commission rejection of PDD funding will likely foreclose any future utility development of generation projects.

Regarding the uneven playing field argument, SCE has stated that it will include all costs of developing a project when conducting comparisons of development projects. The company indicates that it would do so by either tracking the specific costs associated with the development project and then adding it to the SCE estimated cost of the project, or by adding an agreed upon percentage of a project's total budget to the SCE estimated cost. SCE states that its proposal fully expects the ratepayer-funded PDD costs to be accounted for when SCE is comparing the projects it develops to independently developed ones.

SCE also states that the PDD was designed and proposed to support a number of utility needs that are integral with the future of generation in California, even if not one utility generation project is ever developed. Support functions that will be provided by the PDD include: (1) identifying locations for new generation, (2) evaluating generation technologies, (3) tracking regulatory

and legislative generation-related initiatives, and (4) the development of the best option outside negotiation (BOON) for future generation needs. SCE makes the following points:

- A significant portion of a utility's generation planning effort is to identify its generation need, and more specifically, the need for locational generation. The PDD has been designed to identify specific sites for generation that can be used to support locational generation needs. This is an essential function, whether the generation is built, bought, or contracted, since locational needs are best served though specific pre-identification of sites within areas that have identified locational need.
- The PDD will also serve as the SCE generation technology characteristics and cost center. The PDD will establish and maintain the knowledge base of generation technologies, costs, and performance for use by itself and other SCE functions, including resource planning. This is also an essential function that serves the utility requirements of resource planning, project development, and RFO development and evaluation.
- Recent regulatory action in developing market price referents, incorporating carbon impacts into generation assessment, analyzing LNG supply impacts, assessing natural gas infrastructure, clean coal, and a host of other generation-impacting activities highlight the need for the PDD. A necessary part of the project development function is the understanding of, and participation in, the myriad of regulatory and legislative processes impacting generation. The PDD will serve this function and represent ratepayers' interests in the future development of generation.
- As a by-product of its project development role, the PDD will also serve to provide ratepayers with utility

> cost-of-service options that represent the BOON for new generation and supply options. The mere presence of the BOON will discipline the market from runaway RFOs by providing an alternative to the exercise of market power by generators, such as was observed during the energy crisis. Furthermore, the BOON, or more appropriately the family of BOON options,[29] will be a useful input and evaluation tool to RFOs, allowing for more precise crafting of requirements.

SCE states that currently, there is no clarity as to whether the Commission desires to have regulated utilities doing project development. According to the Company, while D.04-01-050 states that utilities are free to bring generation projects to the Commission on a case-by-case basis, D.04-12-048, without making reference to the previous decision, establishes a paradigm whereby utilities are to compete against independent projects on a "head to head" basis, but are allowed to recover initial costs in excess of their final bid price and any cost under runs must be shared 50/50 between ratepayers and shareholders. SCE states that this lack of clarity makes it impossible for regulated utilities, such as SCE, to determine whether they will be able to propose new generation projects. It is SCE's position that, in light of recent CEC and CAISO predictions of resource shortages, clarity with regard to the rules under which regulated utilities will be allowed to bring forth new generation projects is critical.

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[29] BOON will consist of a family of technologies and supply options, including but not limited to repowers, new development, and acquisitions with a variety of fuels and technologies.

8.4 Discussion

All parties addressing this issue appear to agree that costs for project development must be included in any utility bid to provide new generation. As even SCE recognizes, to not do so, would create an uneven playing field for other potential bidders who have no other means to recover such costs. SCE proposes to track the costs for each project and include such costs when making project comparisons for any proposed utility project. However, the PDD costs would be funded by ratepayers as part of the GRC authorization. If the other parties' recommendations were adopted, there would be no ratepayer funding of any PDD costs except those associated with projects that are ultimately implemented and included in rates. Such recovery would be consistent with the capital recovery of the project itself.

We are not convinced by SCE's argument related to potentially abusive suppliers. With the framework established in D.04-12-048, a competitive all-source solicitation reduces such concerns. Project proponents compete with each other in solicitations and have every incentive to submit the lowest feasible bid. IEPA states that apart from the fact that RFOs to date have had very good results, even if there were to be a "runaway RFO," the Commission has expressly granted utilities the discretion to reject the results of a solicitation if the prices are too high: "If an IOU considers the bids from a particular solicitation too high they have the right to terminate the solicitation." We agree.

SCE's management decision to participate, or to not participate, in the process of developing projects for new generation will probably be determined by its priorities and interests as well as its interpretation of risks associated with Commission actions, including those in today's decision. While we recognize there is value in having more participants such as SCE in the

process, we find it necessary to subject SCE to the same cost recovery risks as faced by independent producers. Independent producers' development costs associated with unsuccessful projects are not recoverable from ratepayers. It is a matter of fairness that SCE assume that same risk, if it chooses to participate.

On the other hand, SCE makes the argument that the PDD will support the future of new generation in California even if they do not develop any projects. Support functions include: (1) identifying locations for new generation, (2) evaluating generation technologies, (3) tracking regulatory and legislative generation-related initiatives, and (4) the development of the BOON for future generation needs. These support functions are desirable and it is reasonable that they be funded in rates. However, the specific costs have not been identified and therefore cannot be specifically included on a forecast basis.

For this GRC, we will exclude SCE's entire PDD request from rates. We will however allow rate recovery of costs that support new generation and that are not associated with proposed projects. SCE should track such supportive project development costs in a memorandum account. Such costs can then be recovered in future rates to the extent that they are incurred, to the extent that SCE can justify their supportive nature, and to the extent that the total recorded PDD costs do not exceed SCE's forecasted amount. We realize the amount of money at stake is relatively small. We also realize that under-expenditures in other areas could be used to fund development costs for specific projects. However, we will implement these procedures and restrictions, because from a policy perspective, we feel it is important that the project development costs for proposed new projects should not be specifically included in rates.

In SCE's next GRC, project development costs for specific projects should be excluded from the request. If SCE chooses to do so, it may identify appropriate support costs and include the forecast of such costs in its request.

Regarding SCE's concern regarding D.04-12-048, and the need for clarity with regard to the rules under which regulated utilities will be allowed to bring forth new generation projects, we note that D.05-09-022 granted SCE limited rehearing on this subject. In granting such rehearing, the Commission stated its basis for the sharing mechanism, acknowledged a lack of an evidentiary record to support the mechanism, and granted limited rehearing to develop a legally adequate record. For these reasons, it is not necessary to address the effects of the sharing mechanism on head-to-head competition in this proceeding.

9. Allocation of Generation Related Administrative & General Costs

The requirement for SCE to have separate rate components for distribution and generation requires SCE to separate or functionalize its requested Commission jurisdictional base related revenue requirements accordingly. For test year 2006, SCE used the methodology that was included in developing the authorized revenue requirements distribution and generation in its last GRC. SCE first assigns O&M costs and capital costs directly between generation and distribution functions. It then uses a labor cost allocator to functionalize those O&M costs and capital costs that cannot be directly assigned (*i.e.,* A&G and general plant costs). Next, SCE functionalizes the other components if its 2006 revenue requirement, including income, payroll and property taxes, by using either a labor or rate base allocator. Finally, for ratesetting purposes, SCE assigns to distribution the A&G and general plant costs initially assigned to generation using the labor cost allocator (except those costs associated with

pensions and benefits, computer costs, and furniture and equipment costs). SCE's methodology shifts approximately $276,300,000 in generation related costs to distribution rates in the test year.[30]

AReM, DAAC and WPTF oppose the reassignment of generation related A&G expenses and general plant costs from the generation function to the distribution function, principally because the methodology runs counter to cost causation principles. They argue there is no point to functionalizing costs if they are simply going to be reassigned arbitrarily to another function and conclude that all generation-related costs should be assigned to the generation component of the revenue requirement.

Both AReM and DACC note that PG&E also functionalizes its A&G expenses and general plant costs between generation and distribution, but does not reassign the generation related overhead to the distribution function.

In addition, AReM and DACC contend that A&G costs related to the Energy Supply and Management (ES&M), Qualifying Facilities (QF), and Resource Planning departments should be directly assigned to the generation functions, because these are substantially generation related activities.

SCE argues that it is not the case that Direct Access (DA) customers are only responsible for distribution-related costs. The Commission has previously recognized that certain generation-related costs are properly borne by all customers. In D.01-01-019, for example, the Commission recognized that utilities – which are required by law to act as the default provider to all retail

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[30] The amount shown has been reduced by approximately $108,000,000 due to SCE's agreement with WPTF's recommendation that not all pension and benefit and

Footnote continued on next page

customers within their respective service territories – must maintain the necessary infrastructure to take back direct access customers that choose to return to bundled service. That decision found that the default service obligation is not cost-free and all electricity customers should pay for it. SCE acknowledges that D.01-01-019 addressed what adders to include with the Power Exchange (PX) Credit received by DA customers. However SCE argues that the Commission's findings regarding what costs are properly borne by DA customers is also relevant in this proceeding.

SCE also disagrees with the DACC and WPTF claim that DA customers already pay their fair share of generation costs through the Direct Access Cost Recovery Surcharge (DACRS). SCE states that because the Commission approved SCE's functionalization approach in D.04-07-022, SCE has included A&G and general plant costs for rate recovery in its base-related distribution revenue requirement since 2004. This has reduced the amount of the competition transition charge (CTC) (a component of DACRS) that SCE's DA customers pay, because in determining the CTC component of the DACRS, SCE's A&G and general plant costs are excluded. SCE states that it is for this reason that AReM's and DACC's comparison of PG&E to SCE falls short. According to SCE, what AReM and DACC overlook is the fact that PG&E includes A&G and general plant costs when determining the CTC component of the DACRS. Therefore, PG&E's DA customers pay these identical costs; they just pay it as a portion of CTC.

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computer, furniture and equipment costs should be assigned to the distribution function.

SCE also opposes the proposal to allocate the costs of the ES&M, QF, and Resource Planning departments directly to generation. SCE maintains that these departments also perform distribution-related tasks as well as generation–related functions. Also, the proposal is one-sided in that it does not consider any other A&G organizations that may be weighted more heavily to the distribution function.

9.1 Discussion

In one sense, the issue of whether A&G expense and general plant overheads related to generation should be recovered from DA customers appears settled. According to SCE, it can recover A&G expense and general plant overheads related to generation, from DA customers, by either charging those overhead costs to all distribution customers (its proposal in this GRC) or by including those overhead costs in the CTC calculation used in determining the DACRS (SCE's characterization of what PG&E does). For issues which affect more than one utility, without good reason to do otherwise, our preference is to provide consistent treatment for the utilities. SCE implies there is consistency by PG&E recovering the overhead costs through the DACRS and SCE recovering the overhead costs through distribution rates, because in both cases DA customers are being charged for the overhead costs. This may be true, but the record in this proceeding is not conclusive. While no party has disputed SCE's claim regarding PG&E, which was brought up in SCE's rebuttal testimony, it is not clear that the effect of using both procedures is exactly the same. Certainly, with the current DACRS cap, the timing of cost recovery would be different. Also, AReM states in its reply brief that "Setting aside the issue of whether such costs should be included in CTC calculations at all, AReM submits that the issue of what costs should or should not be included in CTC is an issue

for the utilities' Energy Resource Recovery Account (ERRA) proceedings, where the Commission has determined CTC issues should be addressed, or, alternatively, the DA proceeding (R.02-01-011)." There is at least an implication that whether A&G expense and general plant overheads should be included in the CTC calculation may become an issue in future ERRA proceedings. If that does occur, there is no telling whether what we might determine in this decision today would be consistent with what is determined in a future PG&E ERRA. That would largely depend on what recommendations are made and what evidence is produced in any future proceeding.

To facilitate regulatory consistency between SCE and PG&E, we will change the treatment for SCE to match that of PG&E. That is cost recovery of the overheads in question, if appropriate, should be recovered through the DACRS. It is more reasonable to address this issue, as well as any concerns SCE has with the DACRS cap, in a proceeding where the principles and calculations regarding DA cost responsibility principally reside. Therefore, SCE should seek cost recovery of generation related A&G expense and general plant overheads from DA customers in its ERRA proceedings.

The proposals to directly assign the three generation related A&G departments to generation will not be adopted. We agree with SCE's arguments that these departments also perform distribution-related tasks, and the proposal is one-sided in that it does not consider any other A&G organizations that may be weighted more heavily to the distribution function. To implement the proposal properly, all A&G costs should first be analyzed for direct assignment and the remaining indirect costs allocated to functions. However, this would be contrary to the current methodology for allocating A&G costs to the FERC

jurisdictional transmission function and inconsistent with our actions in D.03-08-062 in A.01-02-030.[31]

10. Transmission and Distribution Expenses

10.1. Stipulation on Priority 5 Maintenance

SCE's current maintenance priority system uses a five-point numerical rating scheme. Priority 1 corrections require immediate attention because they pose the greatest risk to public safety or system reliability. Maintenance items rated Priority 2 through Priority 4 pose much less risk to public safety or system reliability and are scheduled for repair according to the specific item and the degree of degradation. Priority 5 items are those that pose a greater safety risk to the employees performing the repair than they do to the public or to system reliability if the maintenance is left unaddressed. An example of a Priority 5 maintenance item is a missing or not completely legible high voltage sign, which poses no significant increased risk to public or employee safety but does put an employee at risk when repairing the signage.

Currently, Priority 5 maintenance is performed on an opportunity basis. When a crew is scheduled to work on a pole, they will repair all Priority 5 maintenance items at that work level and below. D.04-04-065 issued in April 2004 in SCE's Line Maintenance OII (I.01-08-029) directed SCE, in consultation with the Consumer Protections and Safety Division (CPSD) to, among other things, "[a]chieve a more defined period within which system

[31] In that decision the Commission accepted the use of FERC's labor allocator methodology to assign A&G and general plant costs to the transmission function and essentially rejected a previous Commission adopted methodology by which directly assignable costs were first assigned to functions and indirect costs were then allocated to functions by a multi-factor.

problems are repaired."[32] Based on its experience up to, during and subsequent to the Line Maintenance OII, SCE has concluded that compliance with that direction could be interpreted to require that the Company establish date certain criteria for all Priority 5 maintenance items. Although the Commission in D.04-04-065 did not absolutely mandate the termination of opportunity maintenance or specify the time frame in which it expects Priority 5 items to be repaired, that decision does ask that the amount of time for making system repairs be decreased.

SCE developed three time-dependent scenarios (5-year, 6-year and 10-year) for moving Priority 5 work from an opportunity-based approach to the Commission-envisioned "defined period" approach, and analyzed which scenario would be best for SCE and it customers. SCE's application request included $40,800,000 per year to perform that work over a 6-year period.

SCE's application request for Priority 5 maintenance was opposed by both DRA and TURN. In its testimony, DRA recommended that SCE continue its current overhead distribution maintenance priority system. Specifically, Priority 5 maintenance items should continue to be repaired as opportunity maintenance. According to TURN, D.04-04-065 does not require SCE to change its Priority 5 maintenance activities in this rate case, and SCE has not complied with the directives of D.04-04-065 to first consult with CPSD and to exhaust other alternatives to accelerated maintenance of all Priority 5 conditions. In its testimony, TURN recommended that the Commission should authorize SCE to continue opportunity based maintenance of Priority 5 conditions until this issue

[32] D.04-04-065, (*mimeo.*), p. 22.

is separately resolved. Even if the Commission were to authorize a change in Priority 5 maintenance, TURN argued SCE's requested budget is excessive and unreasonable.

The issue of Priority 5 maintenance has evolved during this proceeding. Since May 28, 2004, management representatives and staff of CPSD and SCE have worked together in compliance with the Commission's directives in D.04-04-065. As of August 13, 2005, CPSD and SCE have agreed on a set of principles governing a refined priority maintenance system for correcting violations of General Orders (GO) 95 and GO 128. Those principles are set forth in a Memorandum of Understanding (MOU).[33] The MOU would have SCE continue its current opportunity maintenance practice for correction of Priority 5 items until such time as the Commission reviews, approves and authorizes funding for a revised maintenance program to be proposed in SCE's next GRC. In its opening brief, SCE revised its primary recommendation regarding Priority 5 maintenance, consistent with these MOU principles.

On August 29, 2005, SCE, DRA and TURN filed a stipulation regarding the Priority 5 issue. By the stipulation, SCE will withdraw its requested funding for acceleration of Priority 5 maintenance on a date-certain basis, on condition that SCE, DRA and TURN recommend that the Commission: (1) find SCE's current opportunity maintenance approach to Priority 5 maintenance to be compliant with D.04-04-065, and (2) direct SCE to continue its current opportunity maintenance practice for correction of Priority 5 items until such time as the Commission authorizes a change in Priority 5 maintenance

[33] The MOU was identified as Late-Filed Exhibit 166 and received in evidence by ruling dated August 30, 2003.

practices. Consistent with the MOU, SCE would not propose any such change prior to its next GRC. SCE, DRA and TURN identified the stipulation proposal as their primary Priority 5 recommendation in their respective reply briefs filed on September 2, 2005.[34]

10.2 Discussion

By establishing (1) principles for a refined priority maintenance system for correcting violations of GO 95 and GO 128, and (2) a timeline for the development, testing and implementation of these principles, the SCE/CPSD MOU demonstrates a commitment to comply, and progress in complying, with directives in D.04-04-065 regarding SCE's remedial actions regarding such violations. Due to the extent of the costs needed to correct all such identified violations, it is important to ensure that the safety and reliability concerns are addressed in a cost effective manner. The MOU also appears to have this prime consideration in mind.

For the purposes of this GRC, we find that the MOU provides a reasonable basis for SCE and CPSD to address GO 95 and GO 128 violation issues. It is reasonable for SCE and CPSD to continue to work out details for establishing and implementing the new maintenance program. When there is final agreement on the new program, it can be presented for the Commission's consideration and adoption. Since the MOU envisions the implementation and transition period for the new maintenance priority system to begin with SCE's next test year, for this test year 2006 GRC cycle, it is reasonable for SCE to

[34] If the Commission were to decline adoption of this primary recommendation, SCE, DRA and TURN would revert to their recommendations and arguments regarding ratepayer funding of SCE's accelerated Priority 5 maintenance proposal.

continue its current maintenance program. Therefore, there is no need to increase funding for Priority 5 maintenance at this time. For the 2006 –2008 interim period, as long as SCE and CPSD are meaningfully engaged in developing the new maintenance priority system, we will consider SCE's opportunity maintenance approach to Priority 5 maintenance to be compliant with D.04-04-065.

SCE, DRA and TURN are the only parties that addressed the Priority 5 issue, and, with the filing of the stipulation, agree on how to proceed with this issue. The stipulation, as described above, is generally consistent with the development of a new maintenance program, as envisioned in the SCE/CPSD MOU. It reasonably resolves the Priority 5 issue in this proceeding, is consistent with law, is in the public interest, and will be approved.

10.3 Account 560.100 – Advanced Technologies for Transmission System

For Account 560.100, SCE is requesting a total of $8,390,000 for the test year. Included in that amount is $4,100,000 for eight advanced technology projects.

DRA recommends zero funding for these projects arguing that SCE has not quantified any cost savings that justify inclusion of the costs; and SCE has not shown that the historical spending level is insufficient to meet the system function needs for this sub-account.

10.4 Discussion

In general, budgets or incremental budgets to historic recorded amounts must be explained and justified. Studies which show that short-term and/or long-term benefits exceed costs could provide persuasive justification for SCE's incremental budgeted costs. However, in this case, SCE indicates that cost benefits/savings estimates are typically developed as a result of (not prior to)

these types of programs. Therefore, while SCE can provide cost information, the benefits/savings associated with these T&D advanced technology projects or programs are not known.

The descriptions of the potential benefits of the projects provide general information but there is not sufficient information to determine whether the costs are justified in either the short or long term. With this type of analysis and showing it is possible to explicitly include associated costs in rates but it is not possible to explicitly reflect any of the associated benefits or savings, whatever they may ultimately be, in rates for this rate case cycle. This imbalance is troubling. In general, it is our obligation to consider both the costs and, if applicable, the benefits/savings of utility proposals. If the benefits/savings are ultimately small when compared to costs, the proposal should probably not be implemented or included in rates. If the benefits/savings are substantial, it would be reasonable to include both the costs and benefits/savings in determining rates. For the advanced technology programs/projects, the lack of information regarding benefits/savings precludes us from making such determinations.

In this decision, we are authorizing significant increases in T&D O&M and capital expenditures. How the potential benefits of the advanced technology programs/projects relate to SCE's proposals for increased spending is not clear. Whether the advanced technology spending results in the modification of any future spending related to T&D costs has not been shown. SCE states,

> …SCE's advanced engineering program evaluates recently developed technologies which are expected to extend the useful life, enhance utilization and/or provide more cost-effective maintenance of existing transmission assets,

> improve employee and public safety, lower installed costs, and prevents degradation of system reliability. Expenditures for these activities relate to early implementation of new technology, getting enough of the technology into the field for employees to see how well it can be adapted by SDC, gain hands-experience and assess the benefits from an operating perspective. As part of this effort, SCE-specific installation and maintenance procedures will be developed and information collected to enable field-based cost/benefit analyses. Without such installation and maintenance information, detailed cost/benefit analyses would not be possible. (SCE, Ex. 94, p. 50.)

For this type of program the benefits/savings may be more long-term rather than short term. However, from the above statement, it appears SCE expects certain benefits to occur when the advanced technology programs/projects are implemented. What those benefits are will not be known for certain until information is collected.

In general, there is merit in SCE's consideration of new technologies that may benefit the system and ratepayers. We prefer to encourage rather than discourage these activities and will therefore include SCE's proposed costs for this rate case cycle. However, since these technologies appear to have the potential for providing significant benefits, we will also assume a level of cost savings. While in the long term, we would expect the benefits to exceed the costs, for the short-term evaluation process, we will assume savings to equal 50% of the costs, and we will include the net cost of $2,050,000 for the test year.

10.5 Account 562.100 – Aging Workforce

Similar to its test year forecast for SONGS O&M costs, SCE includes an adjustment to provide additional staffing needed in advance of an anticipated level of retirements caused by the aging of its T&D workforce. In opposition,

DRA states that (1) SCE has not shown the connection between the age at which its employees are eligible to retire and the age at which they actually retire, and (2) SCE has not shown that its current programs, already funded in rates, are inadequate to meet staffing needs for the next three years. At issue, in this account, are positions associated with five transmission system operators ($600,000).

10.6 Discussion

For the transmission system operators, SCE's rebuttal testimony indicates that out of an estimated 56 operators eligible to retire in 2008, 22 will be age 60 or older and seven would be 62 or older. This contrasts with the projection that, in 2004, 36 operators would be eligible to retire, with four over 60 years old and one at or over 62. The increase in retirement-eligible employees from 2004 to 2008 is 20, with 18 more being 60 or older and 6 more being 62 or older. SCE's testimony indicates that the mean, mode and median age of Transmission Distribution Business Unit (TDBU) employees who retired in the past are all less than 60 and that age 62 is a popular retirement age, partially because of the ability to claim Social Security benefits at that age. The utility has provided sufficient justification for its incremental request for five positions and the associated $600,000 will be included in the adopted test year estimate for this account. We assume costs necessary to address retirements at the 2004 level are embedded in existing rates.

10.7 Account 566.100 – Training and Safety Meetings

SCE uses a budget-based methodology to forecast $9,492,000 for test year expenses for transmission-related training, safety and first aid meetings.

Included in SCE's requests is incremental funding of $3,214,000 to train new employees joining the company as a result of increased workload.

DRA opposes this request, because, in its opinion, the training relates to SCE's aging workforce request, which DRA also opposes.

TURN does not seen any reason to spend almost 15% of the entire transmission labor budget on these functions and proposes to hold labor spending to 11.5% of transmission labor expenditures, which is slightly higher than the 2003 percentage. This results in a $1,785,000 reduction to SCE's request.

In response to DRA, SCE explains that the training is for 49 FTEs including the five operators to be hired and trained in 2006 to replace retiring operators. The incremental increase is for training to support the increase in workforce where entry level experience and skills related to the construction, operation, and maintenance of the transmission grid are limited. SCE also states that OSHA and other governmental agencies require that much of the training (*i.e.,* First Aid, Asbestos Awareness, Class A driver's license requirements, and Fire Extinguisher) be provided. Additional training is necessary as updates are made to software, test equipment, and utility facilities.

In response to TURN, SCE states that the correct comparison would be the ratio of training costs to total labor, which would include both O&M and capital related labor. That results in a ratio of 5.9% in 2003 and 7.7% in 2006.

10.8 Discussion

SCE's forecast related to training and safety for this account is reasonable and will be adopted. Regarding DRA's adjustment, it is clear that the majority of the incremental training relates to employees hired because of increased workload. Since we have previously included the costs of the five transmission system operators who will replace retiring operators, it is not necessary to adjust SCE's requested training costs for the 49 anticipated employees. Regarding TURN's adjustment, the more relevant comparison

would be to use both O&M and capital labor in determining a ratio of training costs to labor. However, what ratio should be used for the test year is not known. The higher ratio of 7.7% for 2006, when compared to 5.9% in 2003 may be explained by the training required to support the projected increase in workforce where experience and skill sets are limited at the entry level. Even after correcting for the use of total labor, we do not have sufficient support for adjusting SCE's request, based on the training cost to labor ratio, as proposed by TURN.

10.9 Account 566.300 – Incremental Non-Labor Expenses

Account 566.300 records miscellaneous expense generated by other departments and charged back to the business unit through the Interdepartmental Market Mechanism (IMM) system. SCE forecasts the test year amount to be $13,641,000. SCE states there are two significant increases over the 2003 recorded amount. The first is an incremental increase of $1,300,000 related to increased maintenance of older facilities as well as to additional facilities and related maintenance due to SCE's increasing workforce. The second is an incremental increase of $4,400,000 related to Information Technology (IT) department services utilized by TDBU. SCE asserts that increased staffing levels will impose the need for a corresponding increase in IT support.

DRA opposes the adjustments related to both increased maintenance of facilities and IT support, and recommends a test year forecast of $7,941,000 be adopted for this account. DRA indicates that its estimate of workforce increases is less than that of SCE.

10.10 Discussion

In general, SCE's proposed incremental increases for office maintenance appear reasonable. Maintenance on buildings tends to increase as buildings age, and additional workforce requires additional office space and related maintenance. Also, most of the workload increases proposed by SCE have been incorporated in this decision. For that reason, we will include the associated $1,300,000 adjustment in the adopted forecast for this account. However, the SCE's reasons for increased IT costs are not clear. In its testimony, SCE stated, "As discussed in various sub-accounts, TDBU will increase staffing levels in various job classifications; this will impose the need for a corresponding increase in IT support which accounted for $4.4 million of the increase in our test year non-labor request."[35] DRA objected because of the differences in workforce estimates between DRA and SCE. However, in rebuttal, SCE also states,

> "The IT-related incremental expenses are for known and anticipated increases in software license renewal and maintenance of software applications and related O&M expenses critical to the operation of the power grid. Some of these expenses will support software applications, such as the Energy Management System, covered in SCE's capitalized budget that ORA has found reasonable. In addition, the requested incremental expenses include increases in IT hardware development that started in 2004 and will continue through the post-test year period of the GRC cycle. Also included are forecast increases due to deployment of field laptops (field Tools) in support of our Mobile Strategy, and as described, increased data requirements

[35] SCE, Exhibit 32, pp. 69 - 70.

> and workforce growth are also included in this request."[36]

SCE's rebuttal introduced a number of additional reasons for the incremental IT support request, but did not provide any details or quantification. Whether any of this information is contained in workpapers is not known, since the workpapers are not part of the record. While we are inclined to increase costs due to increased workforce, the associated cost is not known. For instance, software application expense for the Energy Management System does not appear to be directly related to increases in workforce. Other reasons given in SCE's rebuttal may justify the portions of the increased cost, at least to some extent, but more detail and cost information are needed to evaluate that completely. In effort to be reasonable and fair, we will adopt $2,200,000 for IT support or 50% of SCE's request. This results in an adopted test year forecast, for Account 566.300, of $11,441,000.

10.11 Account 570.400 – Maintenance of Miscellaneous Station Equipment

For the test year, SCE forecasts Account 570.400 to be $7,698,000. Embedded in that request is $2,682,000 for increased O&M expense related to capital spending and $1,045,000 for substation life extension funding. DRA excluded both adjustments, resulting in its test year estimate of $3,971,000 for this account. Based on the discussions below, the adopted test year forecast for Account 570.400 is $6,653,000.

[36] SCE, Exhibit 94, p. 62.

10.11.1. O&M Related to Capital Spending

SCE's proposed increase in non-labor for this account is primarily due to the increase of miscellaneous O&M costs in support of the large increases in transmission stations. SCE forecasted that amount to be $3,000,000, indicating that was 3.5% of anticipated incremental capital expenditures of $86,500,000. SCE stated that in aggregate related expenses historically have been approximately 3.5% of the overall capital expenditures. As part of its rebuttal testimony, SCE analyzed 36 substation capital work orders and determined a 3.1% ratio of O&M related costs to capital expenditures. SCE modified its increase request accordingly by reducing it to $2,682,000.

DRA objects to the request stating that SCE had only a summary table to support its 3.5% request and the 3.1% study was submitted in rebuttal which was too late for it to be carefully reviewed.

We will adopt SCE's forecast of O&M expense related to increased capital spending. SCE provided the basis for using the 3.5% factor. It could not provide disaggregated information, but use of such historical information to develop a factor and to apply that factor to the anticipated incremental capital is still a reasonable basis for calculating the incremental O&M. The analysis is simple, but the amount of money at issue is not large. DRA could have come up with an analysis of its own, simple or otherwise. However, even though it does not challenge the fact that these costs exist, DRA chose not to recommend any expense based on its criticisms of SCE's showing. In this instance, DRA's estimate of zero is not reasonable. Costs will likely occur and the best estimate should be included in rates. SCE refined and slightly lowered its request as part of its rebuttal testimony. We will adopt SCE's

resultant proposed $2,682,000 adjustment to reflect O&M expense related to incremental capital expenditures.

10.11.2. Substation Life Extension

SCE states that the increase in labor for this account is primarily due to commencement of a life extension program to start a 10 to 15 year maintenance cycle on bulk power disconnect switches, starting with the test year cost of $751,000. SCE also request $294,000 in non-labor costs to support life extension efforts related to replacing deteriorating wood cable trench covers.

DRA asked SCE to provide some support such as engineering reports, failure reports or system reliability reports to support its request. According to DRA, SCE provided nothing but the argument that "…common sense and our experience in the field" justified its proposal. DRA concludes that SCE has provided insufficient evidence that those maintenance activities will extend the useful life of station equipment and recommends the request be rejected.

In this instance, SCE has provided insufficient support for its $1,045,000 request for life extension funding. In rebuttal, SCE did provide a technical paper that explained the need for disconnect replacements and a strategy for replacement. However, for activities that will last from 10 to 15 years, there should be some analysis that quantifies the costs and provides some idea of what the benefits will be. While many aspects of the proposed program are appealing, SCE has provided no information or data to support the development or reasonableness of its $1,045,000 request. We will not include SCE's requested funding in this GRC.

10.12 Transmission Life Extension Program

SCE requests $9,950,000 per year in incremental funding over the next six years for what it calls its Life Extension Program. SCE claims the program is necessary to maintain system reliability in the face of the Company's vast aging infrastructure. Among the activities SCE includes in its Life Extension Program are: transmission tower painting and repair, pole and fixture repair, replacing steel tower members and components, tightening hardware, and washing insulators. It is SCE's position that by undertaking this work on a more programmatic basis, the overall life of the assets can be extended. Also, the maintenance activities of its Life Extension Program are not routine maintenance and that the costs associated with these activities have not been incurred for seven to ten years and thus, are not embedded in the five years of historical data.

According to DRA, SCE has not shown that current funding levels are insufficient to perform appropriate levels of transmission maintenance, and offers no verifiable analysis to show that this Life Extension Program will extend the lives of the assets. DRA therefore opposes SCE's proposed $10,800,000 test year increase.

10.12.1. Account 571.100 - Poles and Structures

SCE requests $8,923,000 for Account 571.100, which relates to maintenance of poles and structures. The forecast is based on the 2003 recorded amount of $2,223,000 plus an incremental $6,700,000 for the transmission life extension program. For the life extension program, SCE proposes to utilize contract labor to inspect, repair and paint 40 to 50 high voltage towers.

DRA opposes SCE's request for the incremental $6,700.000 in ratepayer funds and recommends a test year expense level of $2,223,000 based on the 2003 recorded amount. According to DRA, SCE already receives ratepayer

funding for tower painting, bolt tightening and tower footing and crib wall repairs. Currently, the work is performed on an unscheduled, as-needed basis. DRA states that SCE performed no cost/benefit analysis for this additional transmission maintenance program, and offered nothing but unsupported conclusions to show that this program will result in any savings to ratepayers.

10.12.2. Discussion

In its direct testimony, SCE provided very little justification and support for its transmission life extension program. In a data request response to DRA, SCE provided a list of projects totaling approximately $60,000,000 to further justify its proposal.[37] The response described the tower location, the proposed work (*e.g.* Paint Towers), the estimated total cost, and the reason (*e.g.* Age/Prevent Rust Damage). In 2003, SCE recorded $2,223,000 in Account 571.100. According to SCE's testimony, work included tower painting, bolt tightening, and tower footing and crib wall repairs. With the addition of the life extension program activities, the 2006 request jumps to $8,923,000. There appears to be an overlap in life extension and normal activities, and SCE has not provided an overwhelming amount of information supporting the need and costs of the program. In many ways we agree with DRA's rejection of this adjustment. However, recognizing the system is aging and life extension can be a cost effective alternative to maintaining the integrity of the system, we will not completely reject SCE's request.

SCE indicates these costs have not been incurred over the last 7 to 10 years and are therefore not reflected in the recorded data used for forecasting purposes in this GRC. It is curious that none of the costs occurred in

any of the last five years, unless all towers were painted and all bolts were tightened seven to 10 years ago. Otherwise there would be a more even annual distribution of the activities. The other possibility is that work was deferred for reasons other than need. Spreading any authorized over nine years rather than six, as proposed by SCE, appears more appropriate. Certainly, SCE's actions over the last five years do not demonstrate an overwhelming urgency to perform these activities.

Despite SCE's claim that no such work as envisioned in the life extension program has been incurred over the last five years, we are concerned about the relationship to costs that are embedded in the historic data. For instance the large scale painting program may reduce the need for tower painting that is done normally. Likewise, the bolt tightening aspect of the program may reduce the need to tighten bolts as has been done historically, on an as needed basis. To be conservative, we could remove all embedded costs from the forecast. That would ensure there would be no double counting of life extension and normal activities. It would also ensure that non-recurring historic costs are excluded form the test year estimate.[38]However, realizing that there are continuing activities in this account other than tower painting or bolt tightening, we will instead include 75% of the life extension program in addition to the 2003 recorded amount to forecast the test year. The resultant estimate accounts for

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[37] SCE, Exhibit 94, Appendix C.

[38] For instance, there was discussion of an abnormal expense in 1999 to stencil numbers on tower legs due to SCE renaming some of its tower lines. (SCE, Stueland, Tr Vol.10, p.589)

potential double counting of life extension and recorded costs as well as potential recorded costs that will not be incurred in the test year.

The adjustments to spread reduced costs over a longer period of time, result in an adopted test year estimate of $5,573,000 for Account 571.100, compared to SCE's request of $8,923,000 and DRA's recommendation of $2,233,000.

The forecast is for this GRC cycle only. In the next GRC, SCE should provide a more detailed showing on the need and cost of the transmission life extension program (for poles and structures as well as insulators and conductors). The showing should also demonstrate the incremental nature of the program to alleviate our concerns as discussed above. The continuance and level of the program will be considered and determined based on the evidence presented at that time.

10.12.3. Account 571.200 – Insulators and Conductors

SCE requests $8,656,000 for Account 571.200, which relates to maintenance of insulators and conductors. The forecast is based on the 2003 recorded amount of $5,406,000 plus an incremental $3,250,000 for the transmission life extension program. For the life extension program, SCE states the majority of the costs are driven by the fact that particulate levels and other atmospheric conditions in agricultural areas such as the San Joaquin Valley create an increased risk of tracking on insulators. SCE states that its data shows an increasing trend in transmission circuit outages in the area.

DRA opposes SCE's request for the incremental $3,250,000 in ratepayer funds and recommends a test year expense level of $5,406,000, based on the 2003 recorded amount. According to DRA, SCE already receives ratepayer funding for "hot washing" insulators such as those in the San Joaquin

Valley and SCE provided no problem reports or engineering reports to justify additional hot washing.

In response to DRA, SCE asserts that recent newspaper articles demonstrate the severe particulate problem exists and that its proposed funding for washing insulators represents an effort to be proactive in maintaining the reliability of the transmission system in the face of a known problem.

10.12.4. Discussion

Our concerns regarding the life extension program related to insulators and conductors is similar to that discussed above for poles and structures. For Account 571.200, the incremental life extension costs are $3,250,000 above the embedded 2003 costs of $5,406,000. For the same reasons as stated for Account 571.100, we will reduce SCE's request for Account 571.200. We recognize SCE's need to replace and repair insulators in the San Joaquin Valley, but will spread the costs over nine rather than six years. We will also reduce the life extension program by 25% to account for potential double-counting and non-recurring costs, as discussed previously for poles and structures. Our adopted estimate for Account 571.200 is $7,031,000, compared to SCE's request of $8,656,000 and DRA's recommendation of $5,406,000.

10.13 Account 580.100 – Advanced Technologies for Distribution System

For Account 580.100, SCE is requesting a total of $7,600,000 for the test year. Included in that amount is $2,000,000 for seven advanced technology programs. Of those seven programs, DRA recommends that Distributed Energy Resource Advancements, in the amount of $400,000 be included in rates. For the remaining six programs DRA argues that SCE has not quantified any cost savings; certain described functions are those that SCE has historically been performing and the costs should be embedded in historic costs and rates; and

SCE's showing, which offers only generalizations to justify the addition of the incremental costs, is insufficient.

10.14 Discussion

SCE's request for advanced technologies for distribution is similar to its request for transmission in Account 560.100. As discussed in that account, we do not wish to hinder consideration of advanced technologies but feel it reasonable to reflect a level of associated cost savings. As we did for transmission, we will assume advanced technologies savings for distribution to equal 50% of the cost of advanced technologies for distribution. Therefore, for the $1,700,000 at issue, $850,000 will be included for the test year in Account 580.100.

10.15 Forecast Methodology – Account 580.100 Distribution Operations Supervision & Operations

For the remaining portion of Account 580.100,[39] SCE uses a budget-based forecast to estimate distribution operations supervision & operations expense. DRA uses the last recorded year less $400,000 for Distribution Energy Resource Advancements. SCE estimates $5,172,000 and DRA estimates $5,072,000. The difference is minor. DRA's adjustment for embedded activities is questionable, and we will adopt SCE's estimate for this portion of Account 580.100.

10.16 Account 580.200 – Vehicle Fleet Expenses

Account 580.200 records expenses for services provided to TDBU by other departments' IMM charges. SCE's test year forecast for this account is

[39] Excluding spot bonuses, which are addressed separately.

based on a budget based methodology resulting in a test year estimate of $8,910,000.

DRA's test year estimate for this account is $7,038,000. The $1,872,000 difference relates to forecasts of vehicle fleet expenses. SCE used its budget based methodology and DRA used a four-year historical average. DRA used the years 1999, 2000, 2001, and 2003, excluding 2002 because the number of vehicles purchased that year was significantly lower than any of the other historical years.

SCE argues that the average cost of TDBU vehicles for the years 1999-2003 are not representative of the cost of TDBU's fleets in the future. The major cost of the fleet is medium to large size vehicles (special body and aerial equipment mounted on cabs/chassis). SCE states that the average life of the medium sized vehicles is approximately seven years and the average life of the large sized vehicles is approximately 10 to 15 years. SCE further states that it began a five-year cycle to replace many of the medium and large sized vehicles in 1998, but the energy crisis significantly slowed that effort in 2001 and 2002 and beyond. SCE also asserts that increases in vehicle costs are also driven by the fact that its workload and workforce are increasing.

10.17 Discussion

SCE has provided a persuasive argument to rebut DRA's use of the four-year average. 2001 and 2003 were impacted by financial restraints caused by the energy crisis. However, there is no data or analysis to quantify the effects of not using those years in the average. Also, there is nothing in SCE's direct testimony to support its vehicle costs other than the indication that the costs were developed using a budget based methodology. In its rebuttal, SCE provided reasons why DRA's estimate is low. We agree that the four-year

average likely understates vehicle costs. However, SCE has provided little information to justify its specific request. SCE requests additional vehicle funding of $2,452,000 and DRA recommends additional vehicle funding of $580,000. We have no basis to adopt SCE's forecasted increase. However, to reflect our belief that DRA's estimate is low, we will adopt an increase of $1,516,000, the average of SCE's and DRA's forecasted increases. The adopted test year expense for Account 580.200 is therefore $7,974,000.

10.18 Account 580.500 – Research Development and Demonstration

SCE requests test year funding of $4,200,000 for Research Development and Demonstration (RD&D). SCE also proposes the continuation of the one-way RD&D Balancing Account that was established in 1988.

DRA recommends funding of $1,600,000 based on a three-year average of historical costs. DRA indicates this is an increase of $400,000 over what SCE currently receives for RD&D.

10.19 Discussion

In 2003, SCE spent $1,169,000 for RD&D in this account. For the test year, it proposes a significant increase of $3,031,000 or 259%. We are not convinced that SCE's requested increase is reasonable or necessary. In its direct testimony, SCE provides a brief description of its current RD&D efforts in six different areas[40] in which it expects to utilize its requested funding. SCE includes general descriptions of the programs within each area and the budget for that area. Such support is insufficient to justify a 259% increase in spending.

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[40] Improving Existing T&D Asset Utilization; Advanced T&D Technology Applications; Advanced Communication systems; Distributed Generation; Environmental Resources and T&D Impacts; and End-Use Technologies and Load Impacts.

SCE has provided no detailed information, by project or program that supports its $4,200,000 budget. We have no way of knowing what the scope or cost is for programs or projects that been have historically funded or what the scope or cost is for new or existing programs or projects that are budgeted for the test year. Even by its general descriptions, it is difficult to determine what the existing, continuing and new activities are. There is insufficient support to justify SCE's proposed increase in the authorized spending level. In the absence of such justification, DRA's proposal to use an average of the last three recorded years is reasonable and will be adopted, resulting in a test year forecast of $1,600,000 for Account 580.500.

SCE's proposal to continue the one-way RD&D balancing account is unopposed and reasonable and will be adopted.

10.20 Account 583.400 – Incremental Funding

For Account 583.400, SCE forecasts, estimates $14,328,000 for the test year, based on the 2003 recorded amount of $6,529,000 plus incremental costs of $7,799,000. DRA reduced SCE's forecast of costs for intrusive pole inspections by $1,800,000 and Structural Analysis Methodology (SAM) inspections by $1,708,000, resulting in its test year forecast of $10,820,000. We will adopt DRA's recommendation, based on the following discussion of the differences.

10.20.1. Pole Inspections

SCE completed 96,813 intrusive pole inspections in 2003. SCE plans to conduct 128,940 such inspections in 2006 completing the intrusive pole inspection cycle defined in GO 165. SCE then plans to inspect approximately 70,000 poles in both 2007 and 2008. SCE's requested incremental increase of $1,500,000 is based on the intrusive inspection of 128,940 poles. DRA normalized the number of intrusive pole inspections over the three-year rate case cycle at

89,647 inspections per year. At a cost of $45 per inspection, DRA's adjustment results in reducing SCE's costs for these inspections by approximately $300,000 below the recorded 2003 amount.

DRA's normalization recommendation is reasonable and will be adopted. For the years 2007 and 2008, the post-test year mechanism assumes the test year expense, inflated to post-test year dollars. Under SCE's proposal, where there are significant reductions in the number of inspections in the post-test years, it would collect more money over the rate case cycle for intrusive poles inspections than it plans to spend. Rather than modifying the mechanism to adjust for different expenses levels for each of the post-test years, we prefer to normalize the test year amount, which is an acceptable ratemaking procedure.

10.20.2. SAM Inspections

In 2003, SCE conducted 1,152 SAM inspections for $576,000. For the test year, it requests incremental funding of $2,284,000 to inspect a total of 5,720 poles. DRA believes the request to be unreasonable and instead recommends total test year funding of $1,152,000 for 2,304 inspections.

SCE states that a SAM inspection occurs when a pole fails an intrusive inspection or when an inspector or planner visually inspects the pole and requests an immediate SAM inspection. However, SCE has not provided any information that demonstrates a need to increase the level of spending for this program by a factor of four. There is no indication that there is such a significant backup in meeting the need for inspections caused either by poles failures or visual inspections. However, there is value to the program in that the outcome of the analysis extends the life of the pole. For that reason, we feel that it is reasonable to adopt DRA's recommendation, which doubles the funding for this program.

10.21 Account 586.100 – Turn On and Off Service

This account records the field service and construction expense related to the turning-off and turning-on of meters at the request of the customer. Over 95% of the costs are incurred by the Field Services Organization of the Customer Service Business Unit (CSBU). SCE forecasted the test year labor expense based on the last recorded year plus an adjustment for customer growth, and the non-labor expense using a three-year historic trend of 2001 to 2003 data. This resulted in its test year forecast of $15,636,000.

TURN adjusted the CSBU portion of this account and recommends a reduction of $878,000, or 5.6%. TURN argues that SCE's trending analysis for non-labor costs is inadequately explained and results in an unreasonable double escalation of non-labor costs from 2002 to 2006. Because of its assertion that service turn on/off costs are directly related to customer growth, TURN used customer growth plus 10% to derive non-labor costs of $2,558,000, compared to SCE's estimate of $3,232,000. For labor costs, TURN calculated the average CSBU labor cost per customer over the 1999 - 2003 period and applied it to the customer growth resulting in a forecast of test year labor of $12,200,000 compared to SCE's estimate of $12,404,000.

SCE states that TURN ignores the fact that SCE's labor costs in the 2001 to 2003 time period have increase at a rate faster than customer growth. SCE states that TURN recognizes the need to account for at least a portion of the rising non-labor costs, but provides only a modest increase of 10% in real terms plus customer growth as an arbitrary adjustment to the last recorded year of expense. SCE argues that is insufficient to cover its rising costs, primarily related to vehicles.

10.22 Discussion

For labor costs, both SCE and TURN use customer growth in their calculations. SCE's methodology of using the last recorded year and increasing that amount by customer growth is reasonable and will be adopted. We note that labor costs for this account have increased slightly each year from 1999 to 2003. TURN's methodology results in an adjusted 2003 base year amount, before applying customer growth, which is less than either the 2002 or 2003 recorded amount. The reasonableness of the reduced 2003 level is not supported and we will not adopt TURN's proposal.

For non-labor, SCE's rebuttal indicates that it used a three-year trend (2001 to 2003), to forecast test year expenses. This is different than the Joint Comparison Exhibit statement that it was based on the last recorded year plus customer growth. The recorded adjusted non-labor expense for this account increased from $1,969,000 in 1999 to $2,235,000 in 2003, or 12%. Expenses fluctuated during that timeframe, with the lowest amounts being incurred in 2000 and 2001. As discussed later in this decision, we have concerns regarding the use of three-year trends that include years affected by the energy crisis. SCE's test year 2006 request of $3,232,000 is 44% higher than the 2003 recorded amount. Because of the possible effects of the energy crisis and the fairly moderate increase from 1999 to 2003, we will instead use TURN's methodology, which still provides a significant increase over customer growth. The adopted non-labor test year forecast for this account is $2,558,000.

The adopted forecast for Account 586.100 is $14,962,000 as opposed to SCE's request of $15,636,000.

10.23 Account 586.400 - Aging Workforce/ Forecast Methodology

This account records expenses associated with the operation, inspection, and testing of meters and associated metering equipment. SCE's test year forecast for this account is $7,373,000.

Similar to its aging workforce request in Account 562.100, SCE includes an adjustment to provide additional staffing needed in advance of an anticipated level of retirements caused by the aging of its T&D workforce. For the same reasons that it opposed SCE's aging workforce request for Account 566.100, DRA opposes the request for this account. At issue, in this account is $713,000, primarily associated with six distribution meter technicians.

SCE explains that it has identified a potential turnover rate due to retirements in the meter technician classification of approximately 40% over the next five years. Because of extensive training requirements, SCE states that from 2004 to 2008, it will have to increase its normal meter shop staffing, from 14 to 20 employees, with about one third of this group in formalized classroom training at all times.

TURN notes the SCE is requesting a 22% increase in labor from $4,154,000 to $5,067,000 and an increase of 11.3% in non-labor from $2,072,000 to $2,306,000. TURN recommends an increase of 8% based on its opinion that the cost drivers are not rising nearly as rapidly as SCE's expense request. According to TURN, actual meter tests chargeable to O&M expense were 10% below SCE's estimate for 2004. TURN asserts that SCE has provided no data to support the implication that its training costs will significantly exceed historical training costs due to a 13% increase in FTEs.

According to SCE, for April 2005, year to date, it has completed 10% more request tests than for the same period in 2004. SCE states that the

discrepancy between the 13% increase in FTEs and the 22% increase in labor costs is due to training needs for employee attrition. According to the company, while labor costs for the Meter Services Organization are recorded in several accounts, all training required for workforce attrition preparation will be charged to Account 586.400.

10.24 Discussion

The record for this account is confusing. First, SCE's testimony does not specifically explain or show the development of its test year estimate. Second, DRA states that it objects to an aging workforce adjustment of $713,000 without identifying what those costs represent (employees or training costs or both). Third, there is discussion about forecasted and recorded FTEs in 2004 and 2005, but there is no discussion as to how the numbers relate to SCE's test year labor forecast or the proposed adjustments to the request. Fourth, while there is discussion related to the number of meter tests, there is no discussion as to whether or not the number of meters was specifically included in the development of the test year estimate.

We will first make the assumption that the requested $713,000 in incremental labor primarily represents six meter technicians and their training costs during 2006. There is no indication that any of these employees have been hired yet. As justification for the increase, SCE identifies a potential turnover rate due to retirements (based on age and years of service) of approximately 40% over the next five years. However, SCE does not explain how attrition due to retirements was handled historically and what costs are included in the recorded years. Also, it is not clear whether 40% is the percentage of employees eligible to retire or whether it reflects the number of employees expected to retire. SCE only states that 40% is a potential turnover rate. While SCE has shown that in

general its workforce is aging, a more precise showing on how the number of retiring employees was calculated and how past retirements were accommodated historically is necessary to justify the incremental increases requested by SCE. We will therefore not include SCE's $713,000 aging workforce adjustment in the adopted test year forecast for this account.

There is significant overlap in the labor adjustments proposed by DRA and TURN. In excluding the aging workforce adjustment, it is not necessary to address TURN's proposal related to labor expense. For non-labor, it is not clear how TURN developed the 8% factor when considering the cost drivers. The increased number of tests in 2005 may be reason to increase the factor. We will not reduce SCE's non-labor forecast.

10.25 Account 588.300 - Training

This account records expense associated with managing, supervising and directing training activities. SCE requested $40,008,000 for the test year. The recorded 2003 amount is $21,997,000. DRA recommends an amount of $29,882,000. Both SCE and DRA include an increase of $5,600,000 in 2004 over 2003 adjusted recorded expenses for training of new and existing planners, field tools training, personal grounds training, and new apprentice training. SCE requests another $12,411,000 in incremental funding for 16 training programs. In objecting to 10 of the programs, DRA recommends incremental funding of $2,285,000. SCE stipulates to two of DRA's adjustments: (1) that ethics training be conducted every three years instead of annually (DRA reduction of $733,000) and (2) diversity training will be at the current level, which is consistent with Consent Decree guidelines (DRA reduction of $458,000).

10.26 Discussion

Both SCE and DRA propose significant increases for distribution related training. SCE's test year request is 82% higher than the last recorded year. DRA's estimate is 36% higher. While SCE has explanations for each of its proposed increases, we are not convinced that increases of this magnitude are necessary to provide safe and reliable service. Whether this is the company's wish list or whether each of the programs are needed now is not clear. Whether certain costs are included in the historic years cannot be determined because a complete list of training activities for each of the historic years is not part of the record. Even if a specific activity is not included historically, there is the question as to whether all historic training activities will be necessary in the test year and if not how much of the new training it would offset.

However, we will include training associated with new employees and increased workload. We consider this to be an important activity. For service planner training, apprentice safety training, apprentice skills training and substation operator training, this amounts to $2,819,000 as calculated by SCE in its rebuttal testimony. An additional $661,000 is attributable to SCE's aging workforce. We will not adopt that amount. SCE has provided much information on the number of linemen eligible to retire, but has not provided the connection to the number of employees that will likely retire. SCE only states that if only a portion of employees retire when they are first eligible to retire, it will take a toll on the remaining employees and that its request will allow for a proactive transfer of experienced journeyman lineman skills and judgment to the new employees and thus assure the continued sage and efficient operation and maintenance of it distribution system. The analysis of how many employees will retire when first eligible, or how many employees will retire at any age or age

range, is lacking. We will therefore not adopt SCE's request for incremental training related to aging workforce for this account.

For skills training delivery, SCE has provided information on the effect of new curriculum and increased number of students. The incremental cost of $900,000 appears reasonable and will be included in the test year estimate.

Even though we have provided additional funding for the training of new employees, we are not totally convinced that these types of costs are not at least partially covered by the use of recorded 2003 data and the $5,600,000 increase in 2004 over 2003 that was incorporated in the test year estimates of both SCE and DRA. Because of our concern regarding costs already included in the recorded 2003 base and the magnitude of the proposed increase, we will not authorize additional funding for the remaining training programs at issue. That would be for construction & maintenance accountant training, training evaluation and knowledge management, and software applications.[41] For truly necessary and appropriate activities, we will assume there are funds available in either the portion of the estimate based on the 2003 recorded amount of $21,997,000 or the $5,600,000 increase in 2004.

Even with these adjustments, the 2006 adopted amount for this account is $33,601,000, a 53% increase over the 2003 recorded amount.

10.27 Account 588.800 – Miscellaneous Other

SCE uses a budget-based methodology that is a function of customer growth (currently at 1.5% per year) to forecast $3,467,000 for work-order

[41] For software, SCE provides a list of incremental software programs, totaling $3,200,000 intended to support key business processes and maintain compliance in the CPUC and FERC regulatory environments. However, SCE did not explain how these software applications applied to training, which is the subject of this account.

write-offs, the primary driver of this sub-account. DRA's estimate of $1,689,000 is based on a three-year (2001 – 2003) average of historical/adjusted expenditures. DRA used an average because of fluctuations in this account over time. SCE states it is required, as part of its obligation to serve, to provide various services to customers desiring new service or to expand or change service. SCE argues that expenses for customer growth cannot be reasonably forecast using a three-year average.

10.28 Discussion

Based on recorded information, this account increased by 501% from 2000 to 2001, decreased by 68% from 2001 to 2002, increased by 593% from 2002 to 2003 and increased by 51% from 2003 to 2004. These types of changes do not reflect SCE's customer growth which is now 1.5% per year. Use of customer growth to project this account is not reasonable. The large fluctuations are unexplained by the record and an average is appropriate. However, we will add the 2004 recorded amount of $4,592.000 to the average, which results in a 2006 estimate of $2,354,000.

10.29 Account 590.980 – Division Overheads

Account 590.980 records management and supervision expense that has been allocated to distribution maintenance through the clearing account process. SCE's test year forecast for this account is based on a budget based methodology, resulting in a test year estimate of $23,058,000.

DRA recommends a total of $12,524,000 for this account. DRA uses the last recorded year, 2003, to forecast the test year amount. DRA states that its estimate is consistent with both the three and five-year averages of historical recorded expenses.

TURN recommends a reduction of $2,592,000 from this account and the reallocation of these costs to capital, should the Commission adopt TURN's recommendation on Priority 5 maintenance.

According to SCE, the requested $10,534,000 increase in Account 590.980 is driven by a $14,876,000 increase in the overhead clearing accounts. SCE states that the overhead clearing account growth represents additional work that TDBU expects to perform in the test year. The additional work includes engineering, project management, design and planning support, project economic analysis, project estimating contract review and administration, facility management, work order closing, material management and quality management programs and procedures. As recommended by TURN, SCE agrees to reduce its request by $2,166,000,[42] since this decision does not adopt additional funding for Priority 5 maintenance.

10.30 Discussion

SCE's explanation that increased clearing account activity is related to increased work that the TDBU will perform during the test year is reasonable. Its agreement to reduce the request to reflect the elimination of Priority 5 funding is consistent with that explanation. However, it is not clear why the clearing account costs should be shifted to capital rather than be eliminated, since the increased activity related to Priority 5 maintenance has been eliminated and not shifted to capital. Additionally, this decision does not adopt all of SCE's other TDBU O&M and capital requests for the test year. The fact that we are authorizing less of an increase than requested by SCE indicates that the increase

[42] SCE recalculated TURN's proposed adjustment, which TURN reflects as its recommendation in its opening brief at p. 28.

in clearing account activity should be less as well. Unfortunately, the record in this proceeding does not detail the relationships between clearing account activity and O&M and capital projects and costs. There is no provision or methodology to adjust clearing account activity when related O&M or capital costs are adjusted. However, we will reduce the increase in this account by 40% or $4,200,000[43] to reflect an approximation of the reduction in these clearing account expenses due to reductions in SCE's request for T&D expenses in this decision. TURN's recommended reduction of $2,166,000 is included in this amount.

10.31 Account 593.300 – Supply Expense

Costs incurred in the operation of general storerooms are accumulated in Clearing Account 163.600 and cleared to Account 593.300. SCE used a budget based methodology to forecast test year expenses of $4,152,000.

TURN opposes SCE's request noting the decline in productivity with a forecasted 43% labor increase to handle 26% more material. TURN recommends a 31.8% increase, covering the increased materials handled, 26%, plus a 5% increase for labor per materials handled, which results in a recommended $333,000 reduction to SCE's request.

SCE indicates that the supply expense growth in this account is due to a forecast increase in material spending and a change in the way SCE handles material. SCE states that in 2003, it began establishing regional prefabrication

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[43] T&D expenses increased by approximately $175,000,000 between 2003 adopted and SCE's 2006 request in this GRC. Total reductions to SCE's request reflected in this decision are approximately $70,000,000. This percentage reduction of approximately 40% was applied to SCE's proposed increase of $10,534,000 resulting in the approximate $4,200,000 reduction to Account 590.980.

centers and contractor material laydown yards in various locations, resulting in increased staffing requirements. However, SCE further states it will result in downstream efficiencies such as improved material control, backlog reduction, improved material distribution and utilization, and a reduction in material-related false starts.

10.32 Discussion

We will not question whether SCE should or should not have changed the way it handles materials. However, we will assume that, overall, the new way of handling materials is no less efficient than handling materials the old way. While SCE has reflected the associated increased costs, it has not reflected any efficiency gains in forecasting this account, nor does it refer to other areas where related efficiencies are reflected. TURN's adjustment reflects current efficiency levels, is reasonable and will be included in the adopted test year expense of $3,819,000.

10.33 Account 597.400 – Repair Billing Meters

This account records the costs associated with the maintenance of electric billing meters and ancillary metering equipment. SCE uses the 2003 recorded amounts to forecast the test year labor and non-labor expenses, which total $2,067,000.

TURN opposes SCE's request. The first reason is that SCE reprogrammed 4,000 time-of-use (TOU) meters at a cost of $100 each in 2003, and no such activity is contemplated for the 2004 – 2008 timeframe. The second reason is that repairs of real time energy meters peaked in 2003 at 3,075 and declined by 49% to 1,579 meters in 2004. According to TURN, spending in 2004 was about 7% less than SCE's forecast although the difference between actual spending and SCE's forecast was less than the $400,000 of non-recurring TOU

metering in 2003. Therefore, TURN believes it is reasonable to reduce the labor estimate for this account by $130,000.

SCE states that while TURN is correct in noting that the reprogramming of 4,000 TOU meters was a non-recurring event in 2003, the repair and maintenance of newer more complex meters and the repair and maintenance of older, failing meters will increase in the test year, replacing the reprogramming costs.

10.34 Discussion

While SCE indicates that there will be costs in test year 2006 to replace 2003 TOU reprogramming costs, no details on the quantification of the offsetting costs are provided. Also, for the period 1999 to 2003, the two highest expense years were $1,960,000 in 1999 and $2,062,000 in 2003. According to SCE the number of repairs and associated expense increased in 1999 due to reprogramming 5,200 meters for expired TOU calendars, and 4,000 of these meters were reprogrammed again in 2003. The expenses for 2000 through 2002 ranged from $1,399,000 to $1,691,000. From this information it appears that the reprogramming of TOU meters substantially affects the total expense level for this account. TURN's proposal to reduce SCE's test year labor request by $130,000 is reasonable and will be adopted. We note that the resulting adopted forecast of $1,937,000 is still significantly higher than expenses recorded in the 2000 – 2002 timeframe, when there was no reprogramming of TOU meters.

10.35 Account 456.900 – Added Facilities

For other electric revenues associated with added facilities, SCE used a five-year average of recorded 1999-2003 data to forecast test year revenues of $3,661,000.

TURN characterizes the recorded 1999 amount of $2,728,000 as being anomalously low and excludes it from the average, resulting in a test year forecast of $3,894,000.

SCE opposes TURN's adjustment, stating that 1999 is not low when compared to both 1998 and 2004 and from 2001 to 2004 there is a downward trend in revenues. SCE also notes that its forecast is above the 2004 recorded amount of $3,281,000.

10.36 Discussion

From the data presented, an average appears to be an appropriate estimating methodology for this account. However, whether SCE's five-year average or TURN's four year average is better is not clear. We will compromise by using the most recent five-year historic average (2000 – 2004) to forecast test year revenues for added facilities amounting to $3,759,000.

10.37 Audit of Other Operating Revenues

During this proceeding, TURN and SCE reached an agreement about costs associated with generating Other Operating Revenue (OOR) subject to the Gross Revenue Sharing Mechanism adopted in D.99-09-070. The agreement is as follows:

> Per agreement with TURN, SCE will perform an audit of its compliance with the requirements of D.99-09-070 which adopted SCE's Gross Revenue Sharing Mechanism for revenues received from its non-tariffed products and services. SCE will submit the results of this audit as a compliance item in its next general rate case. As part of this audit, SCE will review its determination and recording of incremental and non-incremental costs related to non-

> tariffed products and services from the adoption of D.99-09-070 (September 1999) to the present.[44]

The agreement between SCE and TURN is reasonable, is unopposed and will be adopted.

11. Customer Accounts Expenses

11.1. Accounts 902 and 903 – Non-Labor Forecast Methodology

For the non labor portion of four accounts -- Account 902, meter reading; Account 903.200, credit; Account 903.500, billing; and Account 903.800, call center, SCE used a three-year trend of 2001-2003 data to forecast test year expenses. SCE expects non-labor costs to increase at a faster rate than customer growth. For the non-labor portion of these accounts, SCE's test year forecasts amount to $30,291,000.

DRA opposes the use of the three-year trend noting that while SCE provides five years of data, it only trends accounts where recent three years of data show an upward trend. Where costs are declining over the last three to five years, SCE did not use trending of non-labor costs but instead increased 2003 costs by the 2003-2006 customer growth. Rather than trending, DRA used the customer growth method for the non labor portion of theses four accounts, as both it and SCE did for the labor costs portion of these accounts. For the non-labor portion of these accounts, DRA's test year forecasts amount to $26,422,000.

For Account 903.200, Aglet supports DRA's adjustment pointing out that r-squared value of 0.81 for three data points is unimpressive. Aglet also notes SCE testimony that states credit related activities were lower than normal

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[44] SCE, Worden, 27 RT 2696-2697. We will interpret the word "present" to mean through the base year of SCE's next GRC.

in 2001, the first year in SCE's trend, and the effects of the 2000 – 2001 financial crisis stabilized in 2002, the second year in SCE's trend.

11.2 Discussion

Use of a trend based on three years of data is suspect in that it has a very limited number of data points and minor variations in any of the years could cause wide variations in the projection of the trend. This potential problem is magnified when considering the time frame of the recorded data used in SCE's trend. In general, due to the 2000-2001 energy crisis, SCE significantly reduced its 2001 expenditures when compared to 2000 costs. 2002 and 2003 were recovery years and the associated increases over 2001 may not be indicative of normal growth in costs. In its testimony, SCE provided reasons for using the three-year trend. We will consider those explanations, the recorded data[45] and our concerns regarding three-year trending of 2001 to 2003 data in addressing each of the accounts at issue.

11.2.1. Account – 902 – Meter Reading

From 1999 to 2003, the recorded adjusted non-labor expense for this account increased from $5,819,000 to $10,139,000, or 74%. Expenses increased for each of the years during that timeframe. SCE's test year 2006 request of $11,661,000 is 15% higher than the 2003 recorded amount. SCE explains that the primary driver for the non-labor trend in this account is vehicle related costs, including fuel. Based on this information, we find SCE's requested

[45] The record evidence in this proceeding does not provide the specific data that was trended. "Recorded adjusted" data contained in SCE's testimony was apparently adjusted further for productivity before trending. We will however examine the "adjusted recorded" data in determining the reasonableness of the trends.

increase to be reasonable and will adopt $11,661,000 for the non-labor portion of this account.

11.2.2. Account 903.200 - Credit

From 1999 to 2003, the recorded adjusted non-labor expense for this account decreased from $4,501,000 to $4,162,000, or 8%. Expenses fluctuated during that timeframe, with the lowest amount being incurred in 2001. SCE's test year 2006 request of $5,157,000 is 24% higher than the 2003 recorded amount. SCE explains that the primary drivers for the non-labor trend in this account are vehicle related costs and IT support. This is not demonstrated by the decrease in costs from 1999 to 2003. Also, our concerns regarding three-year trending of 2001 to 2003 data are applicable here. The first point in the trend, $3,429,000 for 2001, is the lowest of any of the recorded amounts and appears to have been affected by the energy crisis. DRA's test year forecast of $4,350,000, based on customer growth, is more reasonable and will be adopted.

11.2.3. Account 903.500 - Billing

From 1999 to 2003, the recorded adjusted non-labor expense for this account increased from $2,950,000 to $3,434,000, or 16%. Expenses fluctuated during that timeframe, with the lowest amount being incurred in 2001. SCE's test year 2006 request of $5,412,000 is 58% higher than the 2003 recorded amount. SCE explains that the primary driver for the non-labor trend is the automation of systems in recent years due to regulatory mandates. There may be merit in SCE's explanation, but the recorded data does not support its request. Again, our concerns regarding three-year trending of 2001 to 2003 data are applicable here. The first point in the trend, $2,036,000 for 2001, is the lowest of any of the recorded amounts and appears to have been affected by the energy crisis. DRA's

test year forecast of $3,680,000, based on customer growth, is more reasonable and will be adopted.

11.2.4. 903.800 – Call Center

From 1999 to 2003, the recorded adjusted non-labor expense for this account increased from $8,141,000 to $8,359,000, or 3%. However, expenses during this timeframe fluctuated from a low of $7,778,000 in 2001 to a high of $10,433,000 in 2000. SCE's test year 2006 request of $8,061,000 is 4% lower than the 2003 recorded amount. SCE explains that the primary driver for the non-labor trend in this account is new automated systems. Also, outsourcing has caused non-labor increases while providing labor decreases. Because of the wide variance in recorded costs, the non-labor portion of this account does not appear to directly relate to customer growth. While we have concerns with the use of the three-year trend, SCE's test year estimate of $8,061,000 is low compared to the 2003 recorded adjusted amount of $8,359,000 or the five year (1999 – 2003) averaged amount of $8,540,000. Based on this information, we find SCE's requested increase to be reasonable and will adopt $8,061,000 for the non-labor portion of this account.

11.3 Account 903.100 - Postage

In its update testimony, SCE identified a U. S. Postal Service requested postage rate increase of 5.4% to be effective as early as January 2006. On November 1, 2005, the U. S. Postal Commission issued its decision recommending the adoption of the postage increase. On November 14, 2005, the Postal Service Board of Governors voted to approve the Postal Rate Commission's recommendation, with an effective date of January 8, 2006. It is reasonable to reflect this known change in postage rates in the calculation of the

forecasted test year postage expense. The test year forecasted postage expense will therefore be increased by $1,018,000, for a total of $20,233,000.

11.4 Account 903.900 – Information Technology Application Services

For Customer Service Application Services, SCE used a three-year trend method to forecast both labor and non-labor expenses for Information Technology Application Services. In support of its trend analysis, SCE states it has provided evidence that growth for this activity will increase at a rate greater than customer growth. SCE's test year forecast for this account is $22,600,000.

DRA recommends the use of 2003 recorded expense, $18,468,000, escalated by 4.53% customer growth to forecast the test year expense. DRA's forecast for this account is $19,304,000.

11.5 Discussion

Our concerns regarding the trending of 2001 to 2003 data, as expressed in the previous section concerning three-year trends of non-labor costs, apply here also. The pattern of reduced spending in 2001 exists for this account also. Recorded 2001 amounted to $15,776,000, the lowest of any of the recorded years. Although SCE has provided explanations for reductions in costs from 1999 to 2001 and increased costs from 2001 to 2003, many of the explanations are not quantified. It is difficult to determine whether the energy and financial crisis of 2000 – 2001 had any effect on spending patterns during the 2001 – 2003 timeframe that was used by SCE for trending purposes.

As mentioned previously, SCE gave explanations of the increased costs during the 2001 - 2003 timeframe. The $1,100,000 labor increase from 2001 to 2002 was due to two factors: transfer of employees from the eBusiness operational unit to IT Application Services for CSBU and full implementation of the Call Workflow Optimization/Computer Telephony Integration project. The

$1,000,000 labor increase from 2002 to 2003 was due to: Client-driven small enhancement requests, full implementation of three projects and realignment between the Transmission and Distribution and Customer Services business units. For non-labor, SCE indicates that expenses remained relatively constant for this account from 2001 to 2003.

SCE explains the 2003 to 2006 increases for this account relate to anticipated regulatory driven initiatives.[46] While regulatory driven costs recorded during the 2001 to 2003 timeframe have not been quantified, certainly some of the costs incurred during that timeframe relate to regulatory driven initiatives. However, other historic costs such as realignment of business units and transfer of employees do not, and no reason has been given to justify trending the effect of these costs to the test year. Also, we do not know whether future regulatory initiatives will increase the need for funding in this account or whether supplemental funding will be provided as part of the initiative. In short, we do not feel comfortable in determining that the three-year trend of 2001 to 2003 recorded data reflects costs that should be extrapolated to 2006 to reflect appropriate future regulatory driven initiatives.

In rebuttal, SCE also attributes increases in test year expenses to systems applications to support new customer-related initiatives and adequate maintenance of existing applications, as well as an increase in work requests resulting from regulatory requirements.[47] In addressing efficiency concerns, SCE states that IT applications, by their nature, usually result in productivity savings and refers to Table I-1 in Exhibit 50, which lists historical and future productivity

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[46] *See* Exhibit 56, p. 101.

savings in customer service operations. Associated productivity is reflected in other FERC accounts, as was the case for the Authorized Payment Agency project and the Meter Process Automation project. The productivity effect of completed IT applications appears to be reflected in the test year results of operations. However, productivity related to undefined applications developed within the three-year trend does not appear to be reflected in SCE's forecasts. While SCE is requesting expenses related to future IT projects, it does not appear that its showing reflects potential productivity savings related to such projects.

Given our concerns regarding trending, quantification of regulatory impacts, and productivity, we will not adopt SCE's request for this account. We will instead adopt DRA's customer growth methodology, which incorporates recorded increases through 2003 and allows for 4.53% additional growth through the test year. The adopted test year forecast is $19,304,000.

11.6 Account 904 – Uncollectible Expense

SCE's revised forecast for the uncollectible factor for the test year is 0.278%. This is the sum of the 1999 – 2003 five-year average of 0.266%, plus an additional 0.007% for uncollectible other operating revenue, plus an additional 0.005% for a PROACT adjustment. The PROACT adjustment reflects the impacts of the PROACT-related redistribution of revenues between residential and non-residential customers. SCE's revised forecast reflects agreement with Aglet's PROACT calculation resulting in a modification of the PROACT adjustment from 0.015% to 0.005%.

DRA recommends an uncollectible factor of 0.2708%. This is the sum of the 1999 – 2003 five-year average of 0.266%, plus 0.004% for the late payment

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[47] *See* Exhibit 99, pp. 19 to 22.

charge and approximately 0.001% for the field assignment charge. DRA opposes the PROACT adjustment.

Aglet recommends an uncollectible factor of 0.220%. Aglet averaged the last two years, 2002 and 2003, equaling 0.215%, in developing its uncollectible recommendation. In support of its forecast, Aglet states that the 2004 unadjusted recorded uncollectible factor was 0.212%. Aglet also added 0.004% for the late payment charge and 0.001% for the field assignment charge, as proposed by DRA. Aglet reviewed SCE's calculation of the PROACT adjustment, and while opposing it, calculated that the maximum upward adjustment would be 0.005% rather than the 0.015% requested by SCE.

11.7 Discussion

In SCE's last GRC, the Commission adopted an uncollectible rate of 0.324% based on a five-year (1996 - 2000) average of 0.319% plus a 0.005% adder related to a new late payment charge. While that factor is significantly higher than the 2003 recorded adjusted factor of 0.202% and the 2004 unadjusted recorded factor of 0.212%, based on the data that indicated a rise in the recorded factor from 0.283% in 1996 to 0.348% in 1999 and a decline to 0.311% in 2000, an average appeared to be appropriate and was adopted.

In this proceeding, a five-year average does not appear to be appropriate. The recorded adjusted uncollectible factor has declined from 0.348% in 1999, to 0.311% in 2000, to 0.242% in 2001, to 0.227% in 2002, and to 0.202% in 2003. Aglet calculates the correlation coefficient to be 0.946, meaning that 94.6%of the variability of the results can be explained by the trend over time. We do not anticipate that decline will continue, since recorded information for 2004 indicates that the decline may be flattening out. Aglet's proposal to average

the 2002 and 2003 recorded uncollectible factors is reasonable and will be adopted.

SCE asserts that a major reason for the recent downward trend in uncollectibles is the drop in mortgage interest rates and the boom in refinancing, which has increased customers' disposable income and their ability to pay. However, SCE has not demonstrated the relationship between ratepayers who refinance and ratepayers who are unable or decline to pay their utility bills. Also, while SCE relates uncollectibles to the Federal Funds Rate over the 1999 - 2003 timeframe, the correlation coefficient that indicates that as much as 75% of the historical variation in uncollectible is explained by this relationship is significantly less than the correlation coefficient that indicates 94.6% of the variability of uncollectibles, over the same timeframe, can be explained by just a time trend.

Also, Aglet asserts, and SCE disputes, that the decline in uncollectibles is caused by the impacts of SCE's credit and collections actions. The record is insufficient to quantify the effects of SCE's credit and collections actions and relate the effects to declining or rising uncollectible costs. Interest rates, unemployment, or the economy in general may also have effects on uncollectible expense. More than likely, uncollectibles are affected by a combination of these and other factors. Without more convincing evidence, it is reasonable to evaluate the data over time and consider averaging, trending or use of last recorded year, similar to our evaluation of other expense items.

Regarding the PROACT adjustment, SCE reasonably argues that PROACT changed the balance between residential and commercial and industrial customers in the percentages of SCE's revenue they each represent.

We will reflect the 0.005% adjustment as calculated by Aglet and agreed to by SCE.

SCE, DRA and Aglet agree that an increase of 0.004% for the late payment charge is reasonable and it will be included in the adopted uncollectible rate. Also, based on our resolution, in this decision, of the field collection charge, the associated effect on uncollectibles of 0.001% will also be included in the adopted factor. The adopted uncollectible factor is therefore 0.225%.

11.8 Account 905.900 – Market Research & Communication

For Market Research and Communications, SCE forecasts incremental test year expenses of $1,570,000. The request would fund four programs: Residential Services and Outreach for $464,000, In Language Communications for $275,000, Customer Process Based Satisfaction Survey for $431,000, and Internet Improvements for $400,000. SCE states the incremental increase in funding for these programs will result in improved customer service delivery, increased utility program customer participation and avoided cost savings, such as for postage.

DRA supports the Language Communications activities for $275,000, but does not support funding for the remaining three programs. As discussed below, we also adopt increases of $464,000 for Residential Services and Outreach and $200,000 for Internet Improvements. In total, the test year increases amount to $939,000, as opposed to SCE's request of $1,570,000.

11.8.1. Residential Services and Outreach

SCE proposes increased spending of $464,000 to help it more effectively provide basic customer services to residential customers. SCE plans to conduct market research to determine preferences for basic customer care programs and tell it how residential customers want to interact with the

company. SCE could then determine if current programs and service should be enhanced or discontinue or if new offerings are needed. SCE also plans to broaden its outreach campaigns to help customers become more aware of various programs and service they find valuable and provide information about important issues that impact them.

DRA is concerned that the benefits to customers are not commensurate with the costs. One of the identified benefits of the program is a $64,200 reduction in postage related to customers switching to online billing. While DRA indicates this is far short of the $434,000 spending request, we believe some programs may be justified for reasons other than cost/benefit. In general, the purpose of the program, which is to provide better basic service to residential customers, appears to be appropriate. Assuming some savings such as for postage, the net cost to customers is not substantial. We see overall benefit for this program and will include it in the adopted expense for this account.

11.8.2. Customer Process Based Satisfaction Survey

SCE plans to create a company-wide method for assessing customer satisfaction with the service provided by SCE from an end-to-end process perspective, rather than simply measuring individual transactions. DRA believes SCE should more efficiently utilize its current budget which DRA characterizes as quite substantial.

We will deny SCE's requested funding for this item. We are not convinced that there is an urgent need to change the method for assessing customer satisfaction, as it relates to customer service operations. While the new method would be more comprehensive, SCE has not explained any problems with the current method other than that the overall satisfaction with SCE as a company remains lower. There does not appear to be substantial dissatisfaction

with customer service operations. Dissatisfaction with SCE as a company may be the result of many things, such as high rates, that are not customer service related. Changing the method for determining customer satisfaction related to customer service operations may not be the relevant course of action. If truly desirable, SCE may be able to transition into the new method, at a reduced scale, using existing funding levels. It can be expanded in the future based on analysis of achieved benefits, monetary or otherwise.

11.8.3. Internet Improvements

SCE requests an increase of about $800,000 (split between Accounts 905 and 908) to fully fund its internet design and development function. SCE's last major modification of the website occurred in 2000. SCE indicates that since that time business conducted over the internet has increased and customer expectations for conducting business electronically have continued to evolve. SCE adds that research has also established that customers expect self-service functionality from websites.

DRA opposes SCE's request, characterizing it as more of a wish list with highly speculative savings.

SCE provides a reasonable rationale for expanding the functionality of its website. Use of the internet continues grow and evolve. However, while indicating that it recorded approximately $580,000 for this function in 2003 and that it needs an additional $800,000, SCE's testimony does not provide any information that shows how the approximate $1,380,000 will be spent. Rather than totally deny the additional funding, we will include 50% of SCE's incremental request, or $400,000, split evenly between Accounts 905 and 908. We include the increased funds to recognize the value to customers of

expanded website capabilities, as generally described in SCE's direct and rebuttal testimony.

11.9 Accounts 901, 902 and 903 – Direct Access Cost Growth

TURN asserts that the current pool of Direct Access (DA) customers can decrease, but it cannot increase under the Commission's current rulings. Therefore, there should be no growth in DA related costs for incremental expenses derived as a result of customer growth or three-year trends. TURN recommends that the overall forecast of 2006 DA costs should be capped at the 2003 recorded/adjusted level with no increase to 2006.

SCE does not agree with TURN's proposal. SCE states that DA related costs are now part of SCE's budgets in each operating area (*e.g.,* billing) and are no longer separately tracked. Also because some functions may have relatively fixed costs at any given point in time and other functions' costs will increase faster than customer growth, the average of all functions' costs will increase at around the rate of customer growth. Lastly, SCE states that DA related costs are continuing to increase due to the complexity and uncertainty relating to current DA issues, such as switching rules, load growth rules, relocation rules, and DA cost responsibility.

11.10 Discussion

We will not adopt TURN's adjustment for this proceeding. Expenses in Accounts 901 – 903 may increase for reasons other than customer growth and it would be appropriate for DA customers to pay their share of those increased costs. Because DA costs are no longer tracked, the recorded 2003 DA related costs are not part of this proceeding's record. For the reasons given by SCE, determining the appropriate separate DA related costs and capping those costs would be difficult at best. We also note that the proposed adjustments are not

large. For example, TURN proposes a $38,000 adjustment for meter reading, in contrast to SCE's approximate request of $40,000,000 for that account.

11.11 Account 456 – Direct Access Fees

SCE's current discretionary DA service fees contained in SCE Rate Schedules CC-DASF and ESP-DSF were implemented in 1999. According to TURN, while SCE's other labor and non-labor costs have increased with inflation, its DA service fees have not. TURN therefore proposes a 25% increase in discretionary DA service fees to account for inflation. TURN states that inflation rates for 1999 – 2006 customer accounts labor is forecast to increase by approximately 29% and distribution labor is forecast to increase by approximately 28%. TURN's proposed adjustment results in an increase to other electric revenues amounting to $227,000 for the test year.

SCE states that TURN's proposal to increase DA service fees by 25% is arbitrary. SCE indicates that it is currently in the process of reviewing the costs related these rate schedules and anticipates filing an application with the Commission to update the associated fees. SCE believes that it would be most fair to all affected parties to make such changes through a separate, properly noticed proceeding specifically for that purpose.

11.12 Discussion

TURN's proposal to update the DA service fees to reflect inflation from 1999 to 2006 is reasonable. SCE has not provided any reasons to not do so other than to argue that it would be more appropriate to address this issue in a separate proceeding. While we agree with SCE that it would appropriate to consider changes to the rate schedules in a separate proceeding, it is not clear when SCE will file its application or when any changes will become effective. In the meantime, assuming that some increased cost over the 1999 level is

appropriate, all other customers will be subsidizing the direct access customers. Also, such subsidization may have occurred historically and may be occurring currently, for the same reason. Therefore, rather than waiting for the results from a proceeding that has not even started, we will reflect, for GRC purposes, TURN's proposed inflation adjustment to reflect a 25% increase in discretionary DA service fees in 2006. Until the Commission issues a decision on SCE's anticipated application regarding DA service fees, the proposed 25% increase is reasonable when considering historic escalation.

12. Customer Service and Information

12.1. Account 908 – Program Management

For Program Management, SCE forecasts incremental test year expenses of $1,931,000. The request would fund five programs: the Government and Mid-size Business Services Program for $513,000, In Language Communications for $275,000, Customer Process Based Satisfaction Survey for $432,000, Billing and Payment for $275,000, and Internet Improvements for $400,000. SCE states the incremental increase in funding for these programs will result in improved customer service delivery, increased utility program customer participation, and avoided cost savings, such as for postage.

DRA opposes funding for the Government and Mid-size Business Services program for similar reasons to those provided for Residential Services and Outreach in Account 905. DRA also opposes Customer Process Based Satisfaction Survey and Internet Improvements for the same reasons provided for Account 905. Lastly, DRA opposes the Billing and Payment programs given the uncertainty of participation and postage savings.

For the same reasons as discussed in Account 905 we will adopt an increase of $200,000 for Internet Improvements and deny SCE's request for

Customer Process Based Satisfaction Survey funding. As discussed below, we will include $257,000 for Government and Mid-size Business Services and exclude SCE's request for Billing and Payment Services. In total the test year increases amount to $732,000, as opposed to SCE's request of $1,931,000.

12.1.1. Government and Mid-Size Business Services Program

SCE requests $513,000 to develop an integrated company-wide approach to improve the delivery of basic customer care to government and mid-size business customers. SCE plans to conduct additional research on how each of these customer segments accesses information and performs business transactions, and then tailor processes for conducting business with them. SCE states that this will include determining if programs can be adjusted or redesigned to make it easier for mid-size and government customers to participate.

In general, the purpose of the program, which is to provide better basic service and to expand service to these customer segments, appears to be appropriate. However, this program to develop an integrated company-wide approach appears to be replacing what SCE has done in the past in this area. The amount of historic costs that would no longer be necessary should be reflected, but is unknown. We will approximate the effect by reducing SCE's requested increase by 50%, or $256,000.

12.1.2. Billing and Payment

SCE requests $311,000 to develop billing and payment options utilizing the internet and debit cards. The expense reflects program management, promotion and maintenance costs. SCE states that it expects to improve the level of service for customers who choose to do business with it using these methods and realize future postage savings in much the same

manner as it has experienced with the elimination of paper bills for its On-Line Billing participants. SCE's rationale for providing the services is reasonable. Use of alternative methods for paying bills is increasing and customers' expectations in this area continue to evolve. However, the need for incremental funding is questionable. First of all, there is no development of the $311,000 expected cost in SCE's direct or rebuttal testimony. It is not clear how the cost was derived, or whether the associated reduced postage is somehow reflected to reduce the net cost. Also, given that the total recorded Program Management spending level in 2003 was $6,057,000, SCE may be able to support any net costs of this program from existing funding levels. For these reasons, for this rate case, we will not include incremental funding for billing and payment for this account.

12.2 Account 908 – Economic and Business Development

For the test year, SCE requests $2,499,000 for Economic and Business Development (EB&D) activities. The forecast is based on the recorded 2003 amount of $3,107,000 less $600,000 due to a program change. According to SCE, its EB&D activities retain, expand, and attract industrial customer operations within and to SCE's service territory that would otherwise locate outside of California. The company claims this program is beneficial to all customers by maintaining and increasing electric revenues to cover fixed costs.

In Aglet's opinion ratepayer funding of improvements to California's business climate is unnecessary. Approval of E&BD activities would be contrary to the Commission's "cautious view" of load building and load retention programs. Aglet argues that SCE has not shown that electricity costs cause businesses to leave SCE's service territory, or that customers will benefit from E&BD activities. Aglet's primary recommendation is to disallow all ratepayer funding of all E&BD costs. Alternatively, if Aglets recommendation is not

accepted, the Commission should defer ruling on SCE's funding request until it acts on EB&D policy issues that are submitted in A.04-04-008 and A.04-06-018 (the Economic Development Rate (EDR) proceeding). It is Aglet's position that if the Commission approves any rate recovery, it should require shareholders to pay 25% of E&BD costs.

12.3 Discussion

Aglet states that the policy issues submitted in A.04-04-008 and A.04-06-018 overlap with issues in this GRC proceeding. Following is a partial list of issues in the EDR proceeding, taken from the common briefing outline:

- Is There a Need for EDRs?
- Assessment of Past ED Rates
- What Protection Is Needed to Prevent Free Ridership?
- Are the Benefits of the EDR Program Sufficient to Meet the Public Interest?
- Ratepayer Benefits and the RIM Test
- Shareholder Benefits and Participation
- What Is the Appropriate Method to Calculate Contribution to Margin?

Aglet argues that, if one substitutes "E&BD programs" for "EDRs," then all of the listed issues are germane to this GRC and that there is an overlap of important policy and technical issues. Rather than waiting for a decision in the EDR proceeding, Aglet repeated most of the points presented in the EDR proceeding, in testimony in this GRC.

We will consider Aglet's recommendation in light of D.09-05-018, which was issued in the EDR proceeding (A.04-04-008/A.04-06-018) on

September 8, 2005. In that decision,[48] the Commission supports the continuation of EB&D activities with the following Findings of Fact:

> 1. The cost of electricity is one of the major contributors to the cost of doing business in California. By some estimates electric rates cause about one sixth of what some experts believe is the overall 30% cost premium for doing business in California.
> 2. The implementation of successful economic development projects would benefit ratepayers directly by increasing the revenues available to contribute to the utilities' fixed costs of doing business, thus lowering rates to other customers.
> 3. In addition to direct benefits to other ratepayers, economic attraction and retention activities also provide indirect benefits to ratepayers in the form of increased employment opportunities and improved overall local and economic vitality.

The decision concluded that rate reductions to attract or retain business are in accord with the legislative precept to "encourage economic development" (Pub. Util. Code § 740.4.), and approved modified requests for economic development rates for SCE and PG&E. The Alternate Proposed Decision that would have shareholders pay 25% of discounting costs was not adopted. Consistent with D.05-09-018, we will continue the EB&D program with full ratepayer funding. SCE's test year request of $2,499,000 is adopted.

12.4 Account 908 – Energy Centers

SCE requests $1,817,000 for the test year to support the operation of its Energy Centers. The forecast is based on the recorded 2003 amount of $1,317,000 plus $500,000 for additional displays and training classes in 2006. SCE

[48] Aglet has a pending request for rehearing of this decision.

explains that the Energy Centers are part of the company's delivery of basic customer care. The electrical safety training classes, intended to prevent or minimize incidents involving the use of electrical equipment on a customer site, contribute to its obligation to provide safe service. The additional demand response seminars and exhibits will provide customers with information about available programs and will teach them how to evaluate their potential for demand response, what control strategies need to be put in place, and how to measure the effectiveness of their demand response plan. SCE states that without this program, it would be unable to provide important resources and services that its customers request, and may hinder its ability to support the Commission's public policy objectives for demand response.

Aglet is not convinced that the Energy Centers generate substantial benefits for SCE ratepayers, especially residential ratepayers. However, because the facilities already exist, Aglet does not oppose the current level of expenses. Aglet does oppose the additional $500,000 requested by SCE. Aglet argues that the proposed additional displays and classes are not essential customer services. Aglet states that SCE has not justified a 38% increase in expenses for programs that promise few benefits for ratepayers and substantial good will for SCE shareholders.

12.5 Discussion

In general, the Energy Centers provides valuable services for the non-residential customers it serves. However, SCE's requested 38% increase, to address the increased needs for customer electrical training and demand response program exhibits and related seminars, is not supported by recent post-energy crisis recorded data that shows a reduction in expenses from $1,380,000 in 2002 to $1,317,000 in 2003. In its testimony or rebuttal, SCE does

not claim that the services provided by the Energy Center in 2003 were in any way deficient nor do they provide evidence that supports a 38% growth in activity from 2003 to 2006. We will adopt Aglet's recommendation to exclude $500,000 in forecasted incremental expenses, which results in the adopted test year expense for energy centers of $1,317,000.

13. Customer Service Charges

Following are the current and recommended customer service charges:

Charge	Present	SCE	DRA	TURN
Returned Check	$10	$10	$10	$10
Service Establishment – Next Day	$12	$17	$15	$12
Service Establishment – Same Day	$22	$24	$24	$24
Reconnection at Meter				
Next Day	$14	$19	$17.50	$17.50
Same Day	$25	$26	$26	$26
Night/Weekend	$30	$58	$37.50	$37.50
Reconnection at Pole				
Next Day	$30	$75	$37.50	$37.50
Same Day	$50	$77	$63	$63
Night/Weekend	$60	$93	$75	$75
Field Assignment	$11	$21	$13.75	$11

As in the last GRC, SCE's proposed charges result from cost based studies. Neither DRA nor TURN objected to the studies or the accuracy of the results. However, both DRA and TURN feel it is important to consider other factors in developing these charges.

For the charges at issue, DRA recommends the increases over current charges be capped at 25%, for affordability reasons. DRA considers it especially important that the most basic option of each fee group not be raised too precipitously or excessively.

Affordability is also a key consideration for TURN. TURN agrees with DRA's proposal to adjust the reconnection fees. However, TURN recommends freezing the next day service establishment charge and the field assignment charge.

TURN argues that the service establishment charge is a highly regressive charge that falls disproportionately on lower income people and renters. The record indicates that renters below the poverty level move more often than homeowners or renters in general. Also, the service establishment charge does not alter customers' behavior by causing customers to move or not to move. Because of this and the fact that the charge was just recently increased by 20% in D.04-07-022, TURN recommends that the next day charge be frozen at $12. Alternatively, TURN recommends the increase be limited to at most 10%, the approximate labor inflation from 2003 to 2006.

For policy reasons, TURN recommends that no increase be adopted for the field assignment charge. TURN notes that while the charge is assessed when SCE personnel got to a site to disconnect a customer, it is also assessed when those personnel accept a payment to avoid disconnection. TURN believes preventing any unnecessary disconnections should be an extremely high priority. TURN asserts that disconnections increase costs to everyone by extending the time utility is paid, thus increasing its need for working capital, and by increasing the risk of uncollectibles. TURN's position is that the additional harm from raising the field assignment charge is greater than any potential benefits from reduced subsidies.

13.1 Discussion

In SCE's last GRC, we adopted customer service charge increases that were moderated by our concerns regarding affordability. We feel it is reasonable

to continue to do so. DRA's proposal to cap increases for service charges at 25% above current levels is reasonable. That percentage increase is significantly higher than inflation, and assuming SCE can reasonably control its costs, provides significant movement towards cost based charges.

While the considerations noted by TURN are important, they do not convince us to freeze the service establishment and field assignment charges, or to limit the increases for those charges to inflation only. Low-income ratepayers have other remedies, including the California Alternate Rules for Energy (CARE) discount, to make electricity available to them at a reduced rate. Also, while TURN asserts additional harm from raising the field assignment charge is greater than any potential benefits from reduced subsidies, it provides no quantification of the harm or benefit to support the assertion.

14. Service Guarantee Program

In D.04-07-022, the Commission adopted the service guarantee program for SCE, which addresses certain areas of customer satisfaction performance by providing compensation to certain customers who have been inconvenienced by SCE. Under the service guarantee program, four situations require SCE to pay rebates to customers: 1) failure to meet agreed-upon appointment times; 2) failure to provide service restoration within 24 hours; 3) failure to provide planned interruption notification; and 4) failure to timely and accurately report the first bill. SCE is required to report program results (number of claims made, claims paid, and amounts of money paid) to the Commission on a semi-annual basis. The service guarantees program was implemented on November 8, 2004.

SCE states that these service guarantees will result in ongoing expenses of $802,000 (including credits) and the service guarantee program is unnecessary to the delivery of customer service. SCE notes that the Commission authorized the

program in SCE's 2003 GRC decision stating: "Although we believe that SCE is currently providing satisfactory customer service overall, we feel that customer service is a core element of utility service and thus wish to ensure there is no degradation to SCE's current level of customer service."[49] SCE argues that it shown that, since that decision, there has been no degradation in its key performance measures and customer satisfaction levels, the primary concern of the Commission in adopting the service guarantee program has been shown to be a non-issue, and the service guarantee program should be eliminated.

DRA recommends that SCE retain the service guarantees adopted in the last GRC. DRA states that it was only one month after implementation of the service guarantee program and before any data was reported as a part of the program, that SCE asked, as part of its GRC application filing, that the service guarantee program be discontinued.[50] DRA argues that SCE has no empirical data on whether or not service has degraded or improved as a result of the service guarantee program because the initial data would be available only when the first report is filed in June 2005.

DRA also states that overall customer service is not the primary purpose for the service guarantee program. The Commission has stated that service guarantees are an opportunity for individuals to be repaid when certain commitments are not met:

> [F]or a customer who has had to miss work (often at an hourly wage) only to have the utility employee not appear within a reasonable window of time, the service guarantee is at least a partial compensation and better than nothing. While the goal

[49] D.04-07-022, *mimeo.,* pp. 163 – 164.

[50] SCE filed the application for this GRC (A.04-12-014) in December 2004.

> may be to improve overall customer service, when individual customers are harmed, as with missed appointments, it is fully appropriate to have the compensation go to the individual.)[51]

It is DRA's position that, while overall customer service is a necessary goal for SCE, individual customers have a right to be compensated in certain situations where SCE has failed to meet a service guarantee commitment.

In the event that the service guarantee program is continued, SCE argues it should be ratepayer funded. Included in SCE's cost estimate of $802,000 is a $349,000 baseline amount to fund ratepayer credits. DRA accepts that ratepayers should fund $453,000 for labor and non-labor costs associated with the service guarantee program. However, DRA objects to ratepayer funding of the remaining $349,000 for customer credits indicating it is inappropriate to have ratepayers fund such credits paid to ratepayers. SCE argues that cost recovery of customer credits, in addition to labor and non-labor costs, is reasonable because all three categories represent the true cost of the mandatory program. In SCE's opinion, it would be punitive to shareholders to require that costs related to the credits be a direct reduction to earnings. SCE also states that its proposal for a baseline of credits is consistent with how companies manage costs associated with service commitments.

14.1 Discussion

The service guarantee program supplements SCE's customer satisfaction efforts by addressing the impact on individual customers when SCE

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[51] D.05-03-023, *mimeo.*, p. 53. This Decision adopted service guarantees for SoCalGas, and continued guarantees for SDG&E. The Commission adopted service guarantees for PG&E in D.00-02-046.

fails to meet its commitments related to four important elements of customer service. We believe this is an important and effective tool for SCE to demonstrate to its customers that it is serious about its commitments and that the program has a positive effect in maintaining or improving SCE's current level of customer service. SCE should continue the program as adopted in D.04-07-022.

In D.04-07-022, the Commission adopted the service guarantee program but did not provide incremental funding for implementation and administration of the program. For test year 2006, SCE forecasts the ongoing costs to be $802,000. It is reasonable that the forecasted ongoing labor and non-labor costs (excluding payments to affected customers) be reflected in rates. Regarding the payments to customers, these are payments that result from the company not meeting its commitments to individual customers. If the company is unable to meet its commitments, the shareholders and not the ratepayers should be responsible for reimbursing the inconvenienced customer.

The incentive for the company to meet these service commitments can be framed in two different ways. One way is to set a baseline and, to the extent SCE was able to reduce missed commitments below the baseline amount, shareholders would gain. The other way is to set the entire liability on shareholders. To the extent SCE was able to reduce the number of missed commitments, the negative effect on shareholders, in the form of payments to affected customers, would be lessened. Setting a baseline is difficult. It should be set at a level that sets a reasonable stretch target for the company to meet. The record in this proceeding, however, is insufficient to develop such a target. Also, the amount of money at stake is small. SCE estimates it to be $349,000 in the test year. For these reasons, we prefer to set the incentive by assigning the liability for missed commitments to shareholders.

15. A&G Expenses

15.1. Results Sharing

15.1.1. SCE's Request

SCE forecasts results sharing expenses of $88,642,000 for test year 2006.[52] Costs are recorded in Accounts 500, 588, 905, and 920/921.

The stated intent of the Results Sharing program is to link 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 against related clear and measurable business goals. Bargaining-unit employees participate at the same level and under the same guidelines as other non-exempt employees. Each year, the results sharing award will increase or decrease based on overall SCE business results.

Apart from the Results Sharing program for bargaining unit/non-exempt employees, SCE's results sharing proposal also includes (1) a small group of senior managers (less than 6% of all employees) that are eligible for the Management Incentive Program (MIP), which is based on the same Results Sharing program targets, except for higher potential payouts and greater individual accountability; (2) a small group of employees (less than 1% of all employees) that are eligible for the Major Customer Division (MCD) Incentive Compensation Plan, which is based on similar Results Sharing program targets, except for higher potential payouts and greater individual accountability; and (3) executives who are not officers that are eligible for the Executive Incentive

[52] As reflected in the Joint Comparison Exhibit.

Compensation Plan (EIP) which is based on a set of measurable, Company performance goals approved by the Board of Directors.[53]

SCE states that, while individual and business unit performance are important components of SCE's Results Sharing program, SCE operating income has the potential to have the biggest impact on the Results Sharing payout.

SCE states that its request for full cost recovery from ratepayers is consistent with the Commission's decision in its last GRC D.04-07-022, as well as with the GRC decisions for test year 1994 for Southern California Gas Company (SoCalGas) and test year 1993 for PG&E where the Commission approved the policy recommendations in the report from a thorough Commission-sponsored 1991 workshop on incentive compensation and granted full recovery of the costs of the utilities' employee incentive programs.

15.1.2. DRA's Recommendation

DRA calculates a five-year straight line historical average of the payouts for all four elements of SCE's results sharing program to be $69,000,000. DRA states that ordinarily, it would recommend that ratepayers and shareholders share the expenses of the incentive program with ratepayers bearing no more than a portion of the cost responsibility commensurate with the benefits received from the program. For example, in SCE's last GRC, DRA

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[53] For reference, as of June 28, 2005, SCE's results sharing request was as follows:

Results Sharing	$61,877,000
MIP	16,779,000
MCD	682,000
EIP	8,416,000
Total	$87,754,000

recommended that ratepayers bear 50% of the cost responsibility of the program. However, for this program in this rate case cycle, DRA recommends no ratepayer funding of the Results Sharing Incentive Program for the following reasons:

- First, the data on which the five-year payouts are based is so compromised by years of under-reporting of employee safety incidents and fraud in the customer satisfaction surveys that it has no credibility.
- Second, SCE has not shown that the current results sharing program will provide ratepayers with any better protection from the under-reporting and fraud of the last one, or will result in verifiable ratepayer benefits.

In June 2004, SCE submitted a "PBR Customer Satisfaction Investigation Report" to the Commission. The Report concludes that some SCE employees falsified data to influence the outcome of customer satisfaction surveys. These surveys are used to determine the amounts of incentive payments to reward for SCE customer service.

In December 2004, SCE submitted a "PBR Illness and Injury Recordkeeping Investigation Report" to the Commission. This Report concludes that, "due to under-reporting of work-related injuries and illnesses and the failure to accurately track all such incidents, SCE did not have sufficiently reliable data to support SCE's request for rewards under the health and safety PBR incentive mechanism."

DRA provided details of these reports; and, in its opinion, the data related to two of the components (customer satisfaction and employee safety), which SCE uses to determine results sharing, is not credible. DRA states that, in light of the evidence, using SCE's recorded data as a basis for charging ratepayers for future expenses is unreasonable.

15.1.3. SCE's Response

In response to DRA's recommendations, SCE asserts the following:

- DRA's recommendation, in effect, punishes SCE for its proper and responsible corporate response to a very unfortunate situation. DRA takes the findings from SCE's Customer Satisfaction and Illness & Injury Recordkeeping investigations that were so candidly communicated to the Commission out of context in an effort to disallow the expenses for SCE's Results Sharing program for a future period. That is not only unfair but would, if DRA's recommendation is adopted, create bad public policy: it would discourage open and responsible self-monitoring and self-correction. It would additionally undermine SCE's concerted efforts to manage its workforce by encouraging desired behavior and deterring unacceptable behavior.
- By focusing only on the Results Sharing goals implicated in SCE's Customer Satisfaction and Injury & Illness Recordkeeping investigations, DRA paints a distorted picture of the Results Sharing program. Removing the portion of Results Sharing pay-outs associated with the customer satisfaction and employee safety goals for those organizations impacted by the misconduct identified in the investigations results in a reduction to our Test Year forecast for the program of approximately 7.5%, or $6.5 million. This reflects a "worst case" scenario since it assumes zero progress is made for the two goals.
- DRA's witness completely ignored the corrective actions SCE has taken and is taking to prevent the recurrence of similar data problems, and which were described at length in the

investigation reports she based her recommendation on. Those corrective actions include: (1) taking disciplinary action against employees where the evidence established that they had engaged in wrongdoing or otherwise did not meet SCE's expectations of appropriate conduct; (2) refunding or foregoing nearly $50 million in PBR rewards; (3) reinforcing SCE's values at the management and leadership levels; (4) taking steps to recommit to SCE's core value of integrity; and (5) taking a hard look at SCE's incentive programs to avoid inadvertent "competition" between values and performance measures.

- SCE also, in recognition of the seriousness of the customer satisfaction and employee safety reporting issues found during SCE's internal investigations, reduced the modifier for the Results Sharing program in 2004, which resulted in a lower pay-out to all employees under the program.

15.1.4 Discussion

We will not adopt DRA's recommendation to completely eliminate ratepayer funding of the results sharing program. SCE has investigated the customer satisfaction and the injury & illness recordkeeping problems, has taken actions it believes are appropriate, and has reported its efforts to the Commission's CSPD. CPSD's investigation of the matter is ongoing. Therefore, at this time, we cannot make any conclusions regarding the actions of SCE employees or SCE management regarding the customer satisfaction and the injury & illness record keeping problems.

For setting rates for this GRC, it is reasonable to include a results sharing program. However, until the current CPSD investigations regarding customer satisfaction and injury & illness recordkeeping problems are resolved, SCE should not use the data or information in question in determining results sharing goals and awards. In its next GRC, SCE should provide detailed information on how its final results sharing goals were determined for the 2006 – 2008 period, what steps were taken to ensure the integrity of both the data and the process for making awards, and any further consequences or any required actions imposed by either SCE or the Commission, as a result of the customer satisfaction and injury & illness recordkeeping investigations.

We now address DRA's backup proposal to split results sharing program costs 50%/50% between ratepayers and shareholders. There are a number of previous Commission decisions regarding such allocation of costs of incentive pay responsibility.[54] Costs were either fully reflected or split 50%/50% between shareholders and ratepayers. In D.04-07-022 we declined DRA's recommendation to split results sharing costs 50%/50% between ratepayers and shareholders. First of all, SCE's total compensation was within market and results sharing did not result in SCE's compensation exceeding market. We also noted management discretion to offer a mix of variable and fixed pay. D.04-07-022 also found no evidence that results sharing created outcomes that are contrary to ratepayer interests and concluded that full ratepayer funding of the forecasted amount was justified.[55]

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[54] For instance see D.86-12-095, 23 CPUC 2d 149, 187; D.92-12-057, 47 CPUC 2d 143, 201; D.93-12-043, 52 CPUC 2d 471, 496; and D.96-01-011, 64 CPUC 2d 241, 368.

[55] *See* D.04-07-022, Section 6.7.2.3.2.

We continue to feel that it is important that results sharing (1) not result in compensation that exceeds market levels, (2) be subject to management discretion, and (3) not be contrary to ratepayer interests. However, as a matter of equity and fairness, we also feel it is important to properly align and assign the benefits and costs of results sharing between ratepayers and shareholders. We will adjust SCE's request accordingly.

Apart from total compensation considerations, the Results Sharing program has elements that provide both shareholder and ratepayer costs and benefits. Examining those costs and benefits provides information for determining whether the benefits and costs of results sharing are correctly aligned from the ratepayer and shareholder perspectives.

SCE's statement that operating income has the potential to have the biggest impact on the Results Sharing payout is evidenced by the operating income multiplier which is directly applied in calculating the awards. If the operating income goal is 100% achieved, the multiplier would be 1.0. The multiplier can increase up to a maximum of 2.0 (if 106% of the goal is reached) or decrease to 0.5 (if 94% or less of the target is achieved). In general, there is no direct ratepayer benefit related to the operating income multipliers.

According to SCE, operating income as used in results sharing calculations is the net of operating revenues less operating expenses. It appears to be similar to the net operating revenue that is derived in the standard summary of earnings table used for GRC purposes. In the Joint Comparison Exhibit, SCE's request reflects a net operating revenue amount of $844,096,000.

To the extent that SCE exceeds its operating income goal, most of the increased costs of results sharing (up to $59,000,000) could be funded from the resulting increased net operating revenue (up to $51,000,000). To the extent

SCE fails to meet its operating income goal, the reduced costs of the results sharing (up to $29,500,000) can be used as a partial offset to the reduced net operating revenue (up to $51,000,000).[56] From the shareholder point of view, the potential cost of up to $8,000,000 in a good earning year would be offset by coverage of reduced earnings of up to $29,500,000 in a bad earning year. Whether this aspect of the results sharing mechanism is necessary or correctly designed is questionable. However, the utility's financial performance is more of a shareholder, rather than ratepayer, concern. We will therefore leave the design of this aspect of results sharing up to the company and its employees and assign the benefits and costs to shareholders.

Ratepayer interests are more served by the goals that form the basis of the target results sharing amount before adjustment for operating income. That amount is $59,000,000. While 25% of that target relates to financial goals and performance (O&M budget and core capital budget) that relate primarily to shareholder interests, the remaining 75% of target, or approximately $44,200,000, relates to goals such as customer service, operating excellence, safety and reliability, which appear to have ratepayer value and benefit. We note that $44,200,000 is 50% of SCE's test year results sharing request.

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[56] If SCE's operating income is 94% of target, assuming target is a level that would produce an authorized rate of return, SCE's net revenue would be reduced by approximately $51,000,000. Likewise if operating income is 106% of target, SCE's net revenue would be increased by approximately $51,000,000.

SCE's results sharing request of $88,482,000 for 2006 is calculated as 75% x (2003 maximum payout) x (2006 labor) (2003 labor). The 100% maximum payout would be approximately $118,000,000. The maximum target revenue before adjustment for operating income would be approximately half of that amount or $59,000,000. A 0.5 multiplier would reduce the target amount by $29,500 and a 2.0 multiplier would increase it by $59,000,000.

Based on the above analysis of the costs and benefits of the results sharing program, we find it equitable to assign 50% of SCE's requested results sharing costs to ratepayers and 50% to shareholders. We believe this correctly aligns ratepayer/shareholder costs and benefits. As discussed above, we assume SCE's estimated results sharing awards used for total compensation study purposes are funded partly by ratepayers, partly by increased earnings, and partly by shareholders. Even if SCE were to reduce the results sharing program to reflect only ratepayer funding, the $44,200,000 reduction would result in SCE's compensation being approximately 3% less than market as determined in the total compensation study.[57] The 3% figure is within the study's plus or minus 5% margin of error, and SCE's compensation would still be considered to be statistically equivalent to the market average. We note that SCE's actions, during this 2006 – 2008 GRC cycle, regarding its results sharing awards and the funding of those awards will impact our future view of this program's viability.

15.2. Spot Bonuses

15.2.1. DRA's Recommendation

SCE awards Spot Bonuses to its employees at business units' discretion to recognize outstanding performance. Over the three-year period, 2001 through 2003, SCE gave 14,321 Spot Bonuses totaling $14,114,322. DRA recommends that Spot Bonuses be disallowed from various accounts before forecasting for the 2006 Test Year. The Joint Comparison Exhibit indicates that

[57] SCE indicated that elimination of results sharing would result in SCE's compensation being reduced to 8% below market rather than 1.6% above market. We assume a 50% reduction cutback in the program would result in half of that reduction.

the effect of DRA's recommendation on the 2006 GRC revenue requirement is to reduce test year expenses by $240,000 in Account 560, $328,000 in Account 580, $403,000 in Account 901, and $1,665,000 in Account 920/921.

The Commission addressed the appropriateness of charging ratepayers for spot bonuses in SCE's last GRC decision, stating:

> 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.
>
> …SCE states that 'SCE's total compensation includes a Spot Bonus program,' (SCE 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. (D.04-07-022, pp. 214 – 215.)

DRA reasons that since D.04-07-022 explicitly stated that the reason Spot Bonuses could not be included in the revenue requirement was that they were not included in the total compensation study; and, since Spot Bonuses were again not included in the total compensation study for this proceeding, it is consistent and logical to conclude, for this proceeding, that it is not reasonable to include such costs in the revenue requirement.

DRA also asserts its testimony shows and as SCE's witness confirmed on the witness stand, SCE's use of Spot Bonuses during recorded years has been unreasonable, possibly fraudulent, and definitely not consistent with ratepayer interests. DRA states that its audit revealed:

- In 2003, 5,876 Spot Bonuses were awarded to 2,987 SCE employees.
- Over a three-year period, 2001-2003, 11 employees were given 586 Spot Bonuses. DRA states this is not reasonable.
- One employee, who is in the executive incentive compensation program, received two Spot Bonuses in 2001 for $50,000 each. DRA states that it is unfair for SCE to ask that ratepayers fund additional compensation to an executive management employee.

In DRA's opinion, SCE's recent problems with "misuse" and "misclassification" are ample assurance that Spot Bonuses are contrary to ratepayer interests.

SCE implemented a new method for tracking Spot Bonuses and the basis for awarding an employee with a bonus in November 2004. Because Spot Bonuses are currently not ratepayer funded, and because DRA recommends against ratepayer funding for Spot Bonuses in this GRC, DRA also recommends against including a new tracking system in the revenue requirement.

15.2.2. SCE's Response

In rebuttal, SCE asserts that it demonstrated that the inclusion of spot bonuses in the Company's total compensation would result in it being within 1.9% of market. SCE states it would still be within 5% of market, and the Spot Bonus program does not result in employees receiving above-market total compensation. SCE notes that its analysis assumed that all comparator

companies would not have any spot bonus costs, even though the likelihood is great that at least some of these comparator companies have spot bonus programs similar to SCE's program.[58] SCE therefore claims that its estimate of 1.9% of market represents a worst-case and it would likely be lower if cost data were available with respect to comparator companies.

SCE's witness indicated that he did not disagree with DRA's statement that 586 awards to 11 employees over three years was unreasonable. However, he stated that, in this case:

> It was a misclassification of payments that were made to a group of employees whereby they would be receiving overtime payments, exempt overtime payments, I believe. And what happened was rather than coding it in the appropriate way, they paid through the Spot Bonus Program. To the best of my knowledge, that's something that has been corrected, as have a lot of things since the initial audit that was done around our Spot Bonus Program.[59]

Regarding the new tracking system, SCE indicates that the expenses to develop the system were incurred in 2004 and are not included or reflected in the test year 2006 expense forecast. However, SCE argues that any ongoing maintenance expenses for the system should be included in future

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[58] DRA states that it never considered the possibility of having Spot Bonuses included in the total compensation study, reasoning that it is inappropriate to include Spot Bonuses because they vary greatly from company to company, they are a small part of total compensation and they are not routinely tracked by the consulting firms that are responsible for conducting compensation studies.

[59] SCE/Cogan, 20 RT 1923, lines 18-28.

funding requests since the tracking system is a necessary expense for properly administering and monitoring the program.

15.2.3. Discussion

D.04-07-022 specified two criteria that should be met in order to recover costs of the Spot Bonus Program in rates. The first is that it does not result in employees receiving above-market total compensation. The second is that the program does not produce outcomes that are contrary to ratepayer interests. We will also use those criteria to evaluate the program for this GRC.

Regarding total compensation, SCE has provided convincing testimony that shows that the inclusion of Spot Bonuses would result in it being, at worst, within 1.9% of market. Using the Total Compensation Study's plus or minus 5% margin of error criterion, the Spot Bonus program would not result in SCE's employees receiving above-market total compensation.

The record concerning ratepayer interests is less convincing. In explaining the 586 awards to 11 employees, SCE indicates there may have been a coding error related to overtime charges. It is not clear that the coding error is applicable to only those 586 awards or whether it was possibly applicable to other Spot Bonuses awarded during that same timeframe. Also, while SCE's witness indicates that, to the best of his knowledge, the problem has been corrected, it is not clear if or how the recorded Spot Bonuses were corrected. The appropriate level of test year Spot Bonuses is questionable. Inclusion of inappropriate Spot Bonuses in determining test year expenses is contrary to ratepayer interests.

Also, SCE has implemented a new method for tracking Spot Bonuses and a new basis for awarding an employee with a bonus. The review process and reasons for giving Spot Bonuses are identified in DRA's testimony.

However, neither DRA nor SCE provide any information on the effects of implementing the new system for tracking and awarding Spot Bonuses. The new system was implemented in November 2004, while the embedded recorded data used for forecasting test year costs is for the year 2003. Whether 2003 recorded Spot Bonuses are reflective of what the award level will be under the new system is questionable. SCE's proposal for including Spot Bonuses for test year 2006 is not supported. For this GRC, we will therefore adopt DRA's recommendation to exclude rate recovery of such costs by reducing test year expenses by $240,000 in Account 560, $328,000 in Account 580, $403,000 in Account 901, and $1,665,000 in Account 920/921.

Regarding the ongoing costs associated with the new tracking system, the costs involved here are very small. Moreover, we are not precluding future rate recovery of Spot Bonuses. On a forward looking basis, the tracking system appears to be essential in substantiating how and why spot bonuses are awarded to employees. SCE should be allowed to request and recover reasonable ongoing costs in the future.

15.3 Account 920/921 – Talent Management

Talent Management is responsible for providing strategic and tactical leadership for SCE's talent acquisition, assessment, and employee and organizational development. SCE used a budget-based approach to forecast test-year expenses of $8,483,000 for Accounts 920 and 921. SCE's test year forecast is an increase of $2,014,000 over recorded 2003 costs. SCE states that this increase is due primarily to the costs associated with the Leadership Programs at SCE which were previously funded, in part, by shareholders. Several of SCE's Leadership Programs were expanded or initiated as part of the Consent Decree SCE entered into in 1996. SCE states that, although the Consent Decree expired

in 2003, SCE has continued its commitment to the established programs and is seeking 100% ratepayer funding to ensure their continued success.

DRA used SCE's Last Recorded Year expenses as a basis to forecast SCE's Account 920 of $3,192,000 and 921 of $3,277,000. DRA's proposal results in SCE continuing 100% funding of the Cross-Training and Leadership Program and 50% funding of the Leadership Grant and Leadership @ EIX programs. DRA's recommendations result in SCE shareholders funding approximately $2,000,000 of the $2,335,000 proposed by SCE for 2006.

DRA states that ratepayers and shareholders benefit equally from the Leadership Grant and Leadership @ EIX Programs and should share the costs equally.

Also, DRA states that SCE is requesting funds for positions in its Leadership programs and at the same time is requesting funding for each business group. DRA concludes that because two different SCE business units/departments are requesting ratepayer funding for labor expenses for one employee, SCE is double collecting. According to DRA, there should only be one of SCE's business units/departments requesting salary for each employee in the cross training program. The funding for salary should be transferred between SCE's business units/departments for the temporary placement of the employee for the year that the employee is in the training program.

In response to DRA's recommendations, SCE asserts that the Leadership Programs benefit ratepayers and should be funded by them. SCE provides the following reasons:

- SCE's Leadership Programs provide opportunities for diverse employees to formally develop essential skill sets that allow them to advance in the company

through further education, cross-training programs and mentoring.

- Since SCE has an aging workforce problem, it must invest in the development of its employees or there will be an inadequate set of skills and experience among the company's middle and senior management.
- By developing talent in-house, SCE's Leadership Programs will help avoid significant expenses for recruitment, compensation, signing bonuses, and relocation.
- SCE's Leadership Programs are consistent with the California Utilities Diversity Council's efforts to promote diversity among the California regulated utilities.

SCE terms "incorrect" DRA's assertion that two different departments or business units are requesting funding for each employee that assumes a cross-training position. According to the company, the position in the home organization, which the cross-training participant has temporarily vacated, is not eliminated. The home organization must still complete the work formerly completed by the cross-training program participant, typically by hiring a new employee to perform the work, back filling the position for the duration of the cross-training assignment, or using another SCE employee on overtime basis. The company therefore maintains that there is no request for duplicate funding.

15.4 Discussion

SCE has provided information that justifies the existence of its Leadership Programs. However, the company does not justify the change from full or partial shareholder funding of the programs to full ratepayer funding of the programs. SCE asserts that the Leadership Programs benefit ratepayers and should be funded by them. On the other hand, SCE does not assert that the

Leadership Programs do not benefit shareholders. The relative benefits to shareholders were not addressed despite the fact that shareholders funded $1,580,000 of the program's total of $1,901,000 in 2003. There is a need to justify why it is reasonable for ratepayers to pay for costs previously funded by shareholders. If SCE wants to shift such a large percentage of these costs from shareholders to ratepayers, it should fully address the implicit assumption that shareholders no longer benefit, or never did benefit, from the programs. Lacking such analyses, costs will continue to be allocated to shareholders. However, we will allocate 50% of the Cross-Training Leadership and Executive Leadership Program to ratepayers, in recognition that the program does provide some benefit to ratepayers. Therefore, ratepayers and shareholders will equally share Leadership Program costs, which total $2,335,000 in the test year. The adopted Talent Management test year forecast is therefore $7,315,000.

Given SCE's reasonable explanation of why it has not requested double funding of positions, we will not pursue that issue any further.

15.5 Account 920/921 – Human Resources Client Services

SCE uses a five-year average to forecast $4,880,000 for Human Resources (HR) Client Services. To support the BPI Project, SCE indicates that it is expanding Organizational Development/Organizational Change Management (OD/OCM) activities and the needed funds are in line with the 1999 and 2000 level of expenses. In rebuttal testimony, SCE indicates that, in April 2005, it hired a senior manager to lead the OD/OCM effort and expects to complete staffing the organization by the end of 2005. While SCE's request is $700,000 over 2003 recorded, full staffing for OC/ODM activities will result in incremental costs of approximately $1,500,000.

DRA recommends using SCE's last recorded year expenses of $4,309,000. In DRA's opinion, SCE has not provided sufficient information to support its assertion that its test year expenses will increase to the 1999-2000 levels. DRA argues that SCE implemented methods which reduced its labor and non-labor expenses and that SCE's staffing levels have remained relatively flat from 2001 through 2003. DRA also argues that SCE's rebuttal testimony supporting OC/ODM activities was untimely.

15.6 Discussion

In its prepared testimony, SCE acknowledged staffing reductions that reduced expenses for HR Client Services from the 1999-2000 levels. SCE also indicated it expected expenses related to OD/OCM activities would increase test year staffing levels and expenditures to be more in line with recorded years 1999 and 2000. Recorded amounts were $6,496,000 for 1999 and $5,588,000 for 2000.

SCE's rebuttal testimony provided additional information to support increased OC/ODM activities in the test year. That information which reflects organizational changes starting in the April 2005 timeframe became available about the time DRA issued its testimony. It would have been inappropriate for SCE to make its principal showing in rebuttal or to delay in providing DRA with relevant requested information. However, it is reasonable for SCE to rebut DRA testimony with relevant information that could not have been provided earlier. SCE's principal showing was that a five-year average was appropriate because additional expenses related to OC/ODM would increase test year levels above recently recorded amounts. The rebuttal testimony provides information to support that showing, and we will adopt SCE's test year estimate of $4,880,000.

15.7 Account 920/921 – Executive Compensation

SCE states that the compensation for SCE's executive officers is part of its competitive total compensation package, and includes a level of base salary, incentives and benefits designed to attract and retain well-qualified executives. The company further states that it competes for executive talent from both utilities and other industries, so its salary and incentive programs must be competitive in order to attract the talent it requires. For Account 920/921, SCE forecasts test year executive compensation costs to be $15,385,000, based on an historic average of 2002 and 2003 expenditures. SCE states that the years 2000 and 2001 were affected by the energy crisis.

For the same reasons discussed previously, for recommending that zero Results Sharing program costs be included in rates for this GRC cycle, DRA also recommends zero funding for the Executive Incentive Compensation Plan for this GRC cycle. Also, for the remainder of executive compensation costs in this account, DRA used a four year average of 2000 – 2003 recorded data to forecast test year expenses of $8,707,000. DRA used a four-year average due to fluctuations in expenses and SCE's change in the mix of its executive officers.

While DRA notes that SCE pays its executives total cash compensation at 11.8% above market levels and SCE's executive benefits are 41.3% above comparator companies in the market, SCE notes that if the Total Compensation Study excluded executive incentives (bonuses) from its calculations, the total compensation for executives would be 32.8% below market.

15.8 Discussion

For the same reasons discussed previously, for rejecting DRA's recommendation that zero Results Sharing program costs be included in rates for

this GRC cycle, we also reject DRA's recommendation of zero funding for the Executive Incentive Compensation Plan for this GRC cycle.

In D.04-07-022, the Commission declined to adopt DRA's recommendation that ratepayers and shareholders contribute equally to the costs of executive bonuses. However, our earlier discussion in this decision, regarding the Results Sharing program, stated that, as a matter of equity and fairness, we feel it is important to properly align and assign the benefits and costs of results sharing between ratepayers and shareholders. That applies to the Executive Incentive Compensation Plan as well.

In our discussion of results sharing, we developed a 50%/50% allocation of costs between ratepayers and shareholders based on the described structure of the program and our perception of the relative costs and benefits. Similar information for the Executive Incentive Compensation Plan is not in evidence. However, SCE states:

> In December of each year, the Board of Directors approves a set of performance goals for the Company, and the Compensation Committee adopts these goals as measures that will be used to determine executive bonuses to be paid under the Executive Incentive Compensation Plan. These goals identify critical areas of utility performance and set measurable, challenging standards to define successful attainment. These goals include targets that improve value for both ratepayers (*e.g.*, customer satisfaction, improved safety performance, and financial performance) and shareholders (*e.g.*, improved earnings per share). These goals are emphasized at all levels of the Company

> through the year and focus performance on areas critical to the utility's business success.[60]

The performance goals of the Executive Incentive Compensation Plan are comparable to those used for results sharing. Absent specific information on how executive incentive compensation is structured and calculated, we will assume it is also similar to that for results sharing and similarly allocate 50% of the costs to ratepayers and 50% to shareholders. We will also assume that the appropriate level for 2006 is the five-year historic average amount of $6,026,000, of which $3,013,000 will be included in test year rates.

We recognize that executive compensation, which consists of both base pay and incentive pay, was evaluated as part of the Total Compensation Study, and, in total, SCE's compensation was at market levels. In our decision today, we are not recommending reduced compensation for executive officers. We are merely assigning certain costs to shareholders. This does not appear to be contrary to the purpose of the Total Compensation Study, which obtained competitive compensation data and compared that data to SCE's compensation levels. The Total Compensation Study did not specify or differentiate between ratepayer and shareholder funding for either comparator company compensation or SCE compensation.

For the remaining executive compensation costs in Account 920/921, we will use an average of 2002 and 2003 data, which is reflective of current executive officer levels and salaries and excludes reduced non labor costs related to the energy crisis. This results in test year labor costs of $7,017,000 and non-labor costs of $2,069,000.

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[60] Exhibit 62, p. 103.

The total forecasted test year executive compensation included in Account 920/921 is $12,099,000, as opposed to SCE's request of $15,385,000.

15.9 Account 920/921 – Equal Opportunity Expenses

SCE uses a two-year average of 1999-2000 recorded data to forecast $1,826,000 for non-labor expenses for the HR Equal Opportunity business unit. SCE expects non-labor expenses to return to pre-energy crisis levels.

DRA uses a five-year average to forecast $1,352,000 for non-labor expenses to capture fluctuations.

15.10 Discussion

Both SCE and DRA used five-year averages to forecast the related labor expenses. SCE explains that non-labor costs have not yet returned to pre-crisis levels but SCE anticipates that several programs will return levels recorded in the pre-crisis years 1999 and 2000. While SCE has expressed its intentions, whether costs will return to pre-crisis levels and, if so, how fast that will occur is not clear or certain. The recorded 2003 non-labor expense is $1,090,000. The five-year average used by DRA results in a test year estimate of $1,352,000, and provides an increase of $262,000 over the 2003 recorded level. Due to the uncertainties, DRA's estimate using the five-year average is reasonable and will be adopted.

15.11 Account 920/921 – In-House Legal Resources

For In House Legal Resources, SCE's test year forecast for non-labor expenses recorded in Accounts 920 and 921 is $3,607,000, based on the 2003 recorded amount. Included in the 2003 recorded amount are costs of $267,000 for document and records management software purchase, $459,000 for computer

and outside consulting services, and approximately $200,000 for SCE's Whiteboard Filing Tracking System.

In developing its estimate of $2,680,000, DRA removed, as one-time non-recurring expenditures, $927,000 in 2003 recorded costs related to software purchases, computer and outside consulting services, and the Whiteboard Filing Tracking System.

15.12 Discussion

Recorded amounts for this activity were $2,826,000 in 1999, $2,636,000 in 2000, $2,577,000 in 2001, $2,724,000 in 2002 and $3,607,000 in 2003. DRA's estimate of $2,680,000 is in line with the 1999-2002 expenditure levels. Because of the increase in 2003 over the prior recorded years, it is necessary to determine the recurring nature of the increased 2003 costs. SCE explains that its documents and records management software purchase and the Whiteboard filing Tracking System were shell purchases and that the systems need to be customized to meet the needs of the Law Department. On-going expenses are necessary for refinements and upgrades, new license agreements, and maintenance work. While SCE asserts that the on-going costs will exceed the purchase prices for the systems, there is little evidence to support that claim. We will however continue the funding for these two systems at the purchase price for each of the years in this GRC cycle. Regarding computer and outside consulting services, SCE believes it may need certain services but does not quantify its needs in any way. It is also not clear whether or not some of these types of activities are included in the 1999-2002 recorded data. Continuation of the $459,000 in non-labor test year expenses for computer and outside consulting services is not supported by the record and will not be included in our adopted estimate of $3,148,000.

15.13 Account 920/921 – Tracking In House Legal Expenses

TURN recommends that SCE track in-house legal expenses separately by subject matter or project. TURN provides the following reasons for its recommendation:

- Without such information it is impossible to normalize expenses unusual or non-recurring expenses for ratemaking purposes. SCE has normalized its outside counsel expenses to account for the non-recurring nature of certain energy crisis legal expenses. SCE did not adjust any in-house attorney costs, even though in-house lawyers may have worked on some of the same energy crisis-related proceedings.
- Tracking in-house costs can assist in comparing the cost-effectiveness of increasing in-house staff versus hiring outside counsel, as well as in evaluating relative staff performance and workload distribution. Given the size of SCE's Law department (currently 82 staff) TURN is skeptical that using "experience and judgment," even in combination with regular performance reviews, is always sufficient to perform these management functions.
- It is standard business practice for most law offices to track expenses by case or proceeding for billing purposes. SoCalGas and SDG&E track legal and regulatory expenses (both in-house and outside counsel) by proceeding.

DRA also recommends that SCE be required to track its in-house legal costs, indicting that SCE's ratepayers will be better served if they do. DRA suggests that the Whiteboard and DM/RM systems might assist in this endeavor.

SCE states that, as required by the Commission, SCE's Law Department currently tracks time for work performed on behalf of affiliates. However, whether or not SCE's Law Department should institute a time track system by subject matter should be left to the discretion of SCE's Law Department management. Based on its experience when the Law Department implemented a time tracking system during 1994-1998, SCE concluded that there is no legitimate business reason for it to track the time of its in-house attorneys that would justify the cost and inconvenience of doing so. SCE states that a time track system is not necessary because the Law Department has in place other means to evaluate and allocate work. Work is evaluated and allocated by using: (1) the judgment and experience of the practicing attorney and the supervising attorney, (2) the case team approach (which involves the collaboration of the lead attorney and a case manager to identify resource needs and keep management apprised of the status of regulatory proceedings through regular case meetings), and (3) the employee performance assessment mid-year and annual evaluations.

SCE argues the comparison of SCE's Law Department to that of SoCalGas and SDG&E is inappropriate, because those in-house attorneys work for the parent company and therefore need to track the time spent on utility matters in order to bill their costs to the utility.

SCE also notes that neither TURN nor DRA identified, quantified, or analyzed the costs to SCE's ratepayers of a time tracking system, noting that the Whiteboard and DM/RM systems are document retention and retrieval systems, not time tracking systems.

15.14 Discussion

According to SCE, its experience indicates there is no value in instituting a time tracking system for in-house counsel. The company points to

other means for evaluating and allocating work, including judgment, a team approach, and an assessment of employee performance. These means may suit SCE's purposes. However, from the standpoint of a regulator, these means are difficult to evaluate in analyzing the reasonableness of SCE's in-house legal expenses. As identified by TURN, a time-tracking system may provide types of information that would be valuable from a regulatory standpoint and perhaps even from an SCE management standpoint. However, without more information, we will not impose such a time-tracking system. In its next GRC, SCE should provide a study on, or analysis of, a time tracking system for its in-house counsel. It should include an estimated cost of performing this activity, any perceived benefits or detriments and any analysis related to the tracking system that was in place during the 1994 – 1998 timeframe. With this type of information, we can make an informed decision on the merits of time tracking.

15.15 Accounts 920/921 – Regulatory Policy and Affairs Labor

SCE used a budget based method to forecast a test year expense level of $9,608,000. SCE states that at the end of 2003, SCE Regulatory Policy and Affairs (RP&A) Department had 97 full time equivalents (FTEs) and 10 vacancies. SCE's test year forecast includes the 97 FTEs, the 10 vacancies and eight additional employees to perform work relating to Transmission Owner Tariff, Wholesale Distribution Access Tariff, Advanced Metering and Demand Response, regulatory compliance, and Permits to Construct and Certificates of Public Convenience and Necessity application for new transmission and subtransmission facilities.

DRA used the last recorded year, 2003, to forecast test year labor expenses. DRA states that during the test year SCE will have several regulatory proceedings that will close and that SCE expects other proceedings will expand

and new issues will emerge. Therefore, DRA considers SCE's existing staffing level to be sufficient to address its workload and meet its responsibilities in the test year. Additionally, DRA removed labor expenses associated with SCE's Washington, D.C. Office. DRA's test year estimate amounts to $8,411,000.

15.16 Discussion

We are not convinced that all the additional positions requested by SCE are necessary. As DRA suggests, some proceedings will close, while others are opened. It generally appears that SCE's incremental budgeting over the last recorded year focuses on anticipated increases and fails to fully discuss embedded recorded activities that may not continue through the test year. However, in general it is reasonable to assume some increases in SCE's regulatory responsibilities over time. Also, although it did not quantify the number, SCE indicates that it already has filled some of the 2003 vacancies. Rather than reflecting the filling of 10 vacancies existing in 2003 and eight new positions, we will assume the addition of nine FTEs for the test year. We will therefore adopt a test year expense level of $9,075,000 for RP&A labor. The adopted level implies a continuation of some vacancies and a potential lessening of the workload due to some proceedings reflected in 2003 recorded data closing before and during the test year.

DRA's adjustment to remove labor expenses associated with the Washington, D.C. Office is apparently tied to the fact that SCE removed lease costs for the office from its GRC forecast. Other than that DRA's adjustment is unexplained. SCE asserts that work performed by these employees involves representation before the FERC, and that these costs are allowable pursuant to the CPUC and FERC approved jurisdiction allocation methodology. We agree

with SCE and will not impose an adjustment to remove the Washington, D.C. Office labor, as proposed by DRA.

15.17 Account 920/921 – Environmental Health and Safety, Non-Labor

SCE used a budget-based method to forecast $1,996,000 for non-labor corporate Environmental, Health and Safety (EH&S) expenses included in Account 920/921. SCE states that the last recorded year plus new incremental expense is the most accurate approach to estimating the cost of the new programs that are being developed.

DRA used the last recorded year amount of $1,641,000 to forecast this account. DRA states its method is reasonable, since SCE's recorded 2003 expense increased by $611,000 over the 2002 level.

15.18 Discussion

In its rebuttal testimony, SCE explains that most of the increase in 2003 over 2002 was related to a $456,000 reduction in the 2002 EMF budget. The reduction was specific to 2002 and these non-labor costs were restored in 2003. Other reductions in 2002 related to the energy crisis. We also note that in 2000, the pre-energy crisis non-labor recorded expense was $2,212,000, which is slightly higher than SCE's test year request. SCE's request for an additional $355,000 in non-labor expense to support seven new EH&S personnel to which DRA did not object is reasonable. We will adopt SCE's forecast of $1,996,000 for EH&S non-labor that is included in Account 920/921.

15.19 Account 920/921 – Public Affairs

SCE's Public Affairs test year forecast of $9,120,000 is based on 2003 recorded costs plus a projected increase of $841,000 to cover the expenses to fill six FTE vacancies that existed at the end of 2003 and five new positions in 2006.

DRA recommends a 25% adjustment to SCE's test year forecast of Public Affairs expense, which results in a test year expense estimate of $6,859,000. DRA claims this is consistent with the Public Affairs adjustment adopted in D.04-07-022. Also, based on its review of a 2003 time-tracking study of SCE's Public Affairs activities, DRA concluded that SCE has included inappropriate charges for Public Affairs activities in the 2003 base year which is the basis for SCE's test year request.

In response to DRA, SCE states that the 2003 time-tracking study was a pilot study and that it removed costs associated with lobbying, political support and corporate citizenship/company representation activities performed at the local level on the more recent and appropriate 2004 time-tracking study. SCE also indicates that its request of $9,145,000 already reflects self imposed reductions $1,064,000 based on the 2004 time-tracking study, $2,418,000 for Washington and Sacramento Offices' costs, $173,000 in one-time local lobbying expense, $298,000 in local non-labor expenses.

15.20 Discussion

SCE's time-tracking studies were apparently conducted in response to D.04-07-022, where the Commission disallowed 25% of SCE's Public Affairs request in order to strike a fair balance of ratepayer and company interests.[61] That disallowance was in response to the DRA and Aglet recommendations that 50% of the costs be disallowed. A properly conducted time-tracking study would provide a better basis for allocating public affairs related costs between ratepayers and shareholders. For purposes of this GRC, SCE's use of the 2004 time-tracking study is better than DRA's reliance on the 2003 study which has

been characterized as a pilot study. The 2004 study was more comprehensive, and better reflects the current structure of the Public Affairs Department. We will use it, as proposed by SCE, to differentiate between ratepayer and shareholder cost responsibilities for Public Affairs expenses. However, SCE states that the 2004 time-tracking study results were applied to the 2003 recorded expenses to obtain the differentiation between 2003 expenses that are properly charged to ratepayers and the 2003 expenses that are properly charged to shareholders. It is not clear that this method is entirely correct, since SCE also states that the Public Affairs Department has changed markedly in the time between the respective rate cases, and there are differences in the scope and nature of Public Affairs' responsibilities.[62] Specifically, the legislative and coalitions areas of responsibility were eliminated. What is not clear is whether the 2003 recorded costs have been adjusted to reflect the new scope and nature of Public Affairs before the shareholder/ratepayer allocations were applied.[63] In its next GRC, SCE should redo the time-tracking study to reflect the areas of responsibilities requested for the test year and ensure that the results are appropriately applied to whatever methodology is used to forecast test year expenses for the Public Affairs Department.

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[61] Finding of Fact 191.

[62] SCE/Exhibit 103, pp. 32-33.

[63] For example, if an employee's activities were related 70% to ratepayers in 2003, but after reorganization that employees activities were now related 90% to ratepayers, the application of the 2004 time-tracking study showing the 90% ratepayer share to the 2003 recorded amount would not properly reflect ratepayer cost responsibility in the base year and might result in an inappropriate assumptions regarding the base year amount that is used for forecasting the test year.

Regarding SCE's request for incremental funding over the 2003 recorded adjusted expense level, SCE has filled the vacancies existing at the end of 2003. We will include costs related to those positions in the adopted expenses. We will also impose a 14% reduction to reflect charges to shareholders, based on SCE's 2004 time-tracking study.

Concerning the proposed five additional FTEs in 2006, we are not convinced they are necessary and will exclude them from the adopted Public Affairs expenses. SCE indicates that the new positions are needed to (1) meet new transmission and substation siting requirements as well as other Public Affairs operational and customer service needs; (2) protect ratepayers from local governments creating new revenue sources by establishing or increasing fees sought from electric utilities: (3) reduce the number of cities per region manager from five and one-half to five; (4) provide general education to local governments. In general these activities are not new. To the extent that they are continuing activities, there may well be similar activities embedded in the 2003 recorded that will not extend through test year 2006. Also, the addition of six FTEs in 2004 may reduce some pressure related to these needs. We will provide that incremental funding of $395,000[64] over the 2003 recorded adjusted level of $6,537,000 for labor. Therefore, for Public Affairs, Account 920/921, we adopt $8,749,000 rather than SCE's requested amount of $9,120,000.

15.21 Account 920/921 – ES&M Labor Expense

SCE used a budget-based analysis to forecast the Account 920/921 test year labor expense for ES&M activities, which amounts to $13,541,000.

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[64] (Six positions adopted/11 positions requested) x $841,000 requested x 86% ratepayer share.

DRA agreed with SCE's proposed staffing level for ES&M but calculated the labor expense using an average 2003 labor rate, resulting in its test year estimate of $12,663,000.

SCE asserts that DRA calculated the average 2003 labor rate is incorrect, because DRA used the end of year number of FTEs in its calculation. According to SCE, there were more FTEs at the year endue to the addition of 16 FTEs during 2003. SCE's 2003 labor rates were based on actual salaries paid in 2003 to ES&M employees by job classification.

15.22 Discussion

In order to properly calculate the average salary for 2003, the total labor expense should be divided by the average number of employees for the year, not the year-end number. While a weighted average number of employees for the year would be more appropriate, SCE calculates the simple average of the beginning and end of year employees to be 103 employees, as opposed to DRA's use of 111 end-of-year employees. Use of 103 as the average number of employees results in an average cost of $94,120. When applied to the 145 proposed number of employees for the test year, the result is a higher ES&M labor cost than requested by SCE. SCE's estimate that is based on a cost per employee using actual salaries paid in 2003 is reasonable and its test year ES&M labor forecast of $13,541,000 will be adopted.

15.23 Account 920/921 – Qualifying Facilities Resources, Labor Expense

SCE used a budget-based analysis to forecast the Account 920/921 test year labor expense for the Qualifying Facilities Resource Department. SCE's test year request amounts to $3,656,000 and includes the market costs for three additional employees over the 2003 recorded level.

DRA agreed with SCE's proposed staffing level for QF Resources, but calculated the labor expense by applying the average 2003 labor rate to the resultant 39 FTEs. DRA's adjustment resulted in a test year estimate of $3,590,000.

15.24 Discussion

The difference between DRA and SCE is minor. Whether new employees will be hired at some market rate or something less, or whether the composition of the existing 36 employees will change or remain the same is uncertain. DRA's assumption that the overall net labor cost will be the average salary in 2003 applied to the expected number of employees in 2006 is reasonable. We will adopt DRA's estimate of $3,590,000 for QF Resources labor included in Account 920/921.

15.25 Account 920/921 – Reimbursable Expenses

In SCE's last GRC, the Commission required SCE to "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." (D.04-07-022, p. 240.) Pursuant to that requirement, SCE conducted a review of recorded 2003 reimbursable expenses to verify that reimbursable expenses charged to ratepayer accounts were appropriate ratepayer expenses and not expenses that should be charged to shareholder accounts or below the line. SCE used a Monetary Unit sampling statistical methodology, which selects a statistically representative sample of expense reports to make inferences about the entire population. SCE states that the detailed review of the sample determined that of the 338 expense reports reviewed: 306 expense reports (totaling $297,932) correctly classified either ratepayer or shareholder reimbursable expenses, eight expense reports

(totaling $10,019) could not be located, and 24 expense reports (totaling $40,748) had charged reimbursable expenses incorrectly to ratepayers (totaling $14,104). Based on these findings, SCE proposed to adjust $374,489 of the $14,615,079 recorded 2003 reimbursable expenses.

In contrast to SCE's proposed adjustment, DRA recommends that $1,060,531 of 2003 reimbursable expenses should be shareholder funded and that this amount should be disallowed from Accounts 920 and 921. There are two differences between SCE's adjustment and DRA's adjustment. The first difference is due to DRA's view that 100% of the expenses related to eight expense reports that could not be located should be disallowed. The second difference is due to DRA's assumption that certain recognition related expenses should be shareholder funded.

DRA also took issue with SCE for not reviewing all of the expenses reports for the year associated with the 24 employees who had errors in their expense report included in the sample. DRA also recommends that SCE be ordered to review all reimbursable expense reports for each employee whose annual total reimbursable expenses are $25,000 or more.

With respect to the eight missing reports, SCE applied the 4.29% error rate consistent with the rest of the sample. With respect to recognition awards, SCE states that DRA did not provide any rationale for the disallowance and that SCE's inclusion of such costs is consistent with its last GRC decision. SCE also states that to review all of the expense reports associated with the 24 employees who committed errors would have violated basic sampling principles by examining expense reports that were outside of the sample. SCE also asserts that it is unreasonable to assume employees who make an error on

one report will make the same error on all reports. SCE states that it has a three-tier review of expense reports and it is unlikely that would happen.

15.26 Discussion

We will adopt DRA's recommendation and disallow 100% of the expenses for the missing eight expense reports. While a 100% error rate on those reports is unlikely, the expenses are wholly unsupported and that effect should be included in determining the adjustment. SCE should be able to provide accounting data and backup for its recorded transactions. If it cannot do so, it is reasonable to exclude such costs from rates. DRA states that had the eight missing reports been evaluated at 100% error, the statistical result for the most likely reimbursable expense error would be extrapolated to $687,307. We will adopt and reflect that amount to adjust the recorded 2003 reimbursable expense adjustment to Accounts 920/921.

As recommended by DRA, for the next GRC, SCE agrees to perform a review of all reimbursable expense reports for each employee included in SCE's GO 77-L submittal whose annual total reimbursable expenses are $25,000 or more for any of the years 2004, 2005 and 2006. DRA indicated that would cover approximately 10% of the reimbursable expenses. SCE state that while it will correct any errors found in the review, it is important to note that since the sample will not be statistically significant (selected at random), any error found in the judgmentally selected sample cannot be extrapolated to the entire population. SCE is correct. To cover the approximate 90% of the remaining reimbursable expenses, SCE should also conduct another statistical study for recorded 2006 reimbursable expenses, for the remaining employees whose annual reimbursable expenses are less than $25,000, similar to that performed for 2003 recorded reimbursable expenses.

DRA's recommendation to eliminate recognition awards is similar to its proposal in the last GRC to disallow the SONGS 2 & 3 awards and recognition program. In denying that request, we stated:

> 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. (D.04-07-022, p. 34.)

In proposing its adjustment for recognition awards in this proceeding, DRA did not provide any information or argument that would lead us to conclude that our discussion in the last GRC on this topic should now be disregarded. DRA's recommendation will therefore not be adopted.

15.27 Account 920/921 – Expenses for Compliance with Affiliate Rules

TURN recommends a $225,000 reduction to Account 920/921 to reflect the annual labor expense related to 2.5 FTEs for affiliate rule compliance activities in the Regulatory Policy and Affairs department plus the related non-labor costs, primarily for reimbursable travel expense.[65] TURN states that the Commission has held that the costs for complying with affiliate transaction rules

[65] TURN Opening Brief, p. 93.

should not be charged to ratepayers, since there is no basis to conclude that "ratepayers are in any other way the primary beneficiaries of [the utility's] decisions to diversify into non-regulated activities."[66] TURN further states that SCE has made no showing in this case to disprove the Commission's conclusions regarding the need for benefits of affiliate compliance activities. TURN suggests that SCE can allocate the costs to affiliates or shareholders.

TURN's proposed adjustment is consistent with Commission precedent, is not disputed by SCE, and will be adopted.

15.28 Account 923 – HR Consulting Expenses – Executive Compensation

Consulting expenses related to executive compensation are included in Account 923. SCE uses a five-year average to forecast $844,000 for this activity. SCE states that this methodology recognizes the fluctuating expenses over the last five years for outside services.

To estimate this account, DRA used recorded 2003 expenses, reduced by $226,000 for one-time, nonrecurring costs related to compensation design and an executive benefit index valuation study. DRA's methodology results in an estimate of $790,000.

15.29 Discussion

SCE's rebuttal testimony indicates that the costs identified by DRA as being one-time and non-recurring are ongoing in nature. While postponed during the energy crisis, the executive benefit valuation study is conducted every three years. Benchmarking studies are also needed and used to demonstrate the reasonableness of total compensation. It appears these activities may not be

[66] D.00-02-046, mimeo, p. 276.

required every year but may be incurred in conjunction with GRCs. However, even if the $226,000 were normalized at $75,000 per year over the three-year GRC cycle, the resulting estimate would be greater than either SCE's or DRA's estimates, which differ by only $54,000. SCE's estimate of $844,000 is reasonable and will be adopted.

15.30 Account 923 and 928 - Law & Regulatory

SCE based its forecast of $8,226,000 for Account 923 and $3,111,000 for Account 928 on three-year averages (2001-2003) of recorded amounts. SCE states that it adjusted the recorded amounts for nonrecurring energy crisis effects, resulting in adjusted recorded expenses for Accounts 923 and 928 of $14,372,000 in 2001, $11,427,000 in 2001, $11,427,000 in 2002, and $8,212,000 in 2003. SCE also states that beginning in 2003 outside counsel costs began to taper off with the diminishing energy crisis and increase in the umber of in-house attorneys.[67] SCE asserts that expenses for 2006 will be higher than recorded 2003 due to increasing legal challenges in such areas as ISO tariff amendment, Sarbanes-Oxley compliance work and EMF issues.

DRA utilized the 2003 recorded amount of $6,366,000 for Account 923 and $1,846,000 for Account 928 as the bases for its estimates. DRA argues that data for years affected by the energy crisis should not be used for forecasting purposes. DRA also state that, for Account 923, the use of last recorded year is a more accurate reflection of where SCE's costs are headed as SCE has shown that as its in-house legal increased, its need for outside counsel has dramatically decreased.

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[67] SCE, Exhibit 71, p. 21

For Account 928, DRA further reduces its estimate to remove what it considers to be a one-time, nonrecurring expense; that being $1,505,000 associated with SCE's past participation in the Commission's Gas Border Price Investigation. DRA's test year estimate for Account 928 is therefore $341,000.

15.31 Discussion

DRA's use of recorded 2003 as the base for forecasting test year expenses is more appropriate than SCE's three-year average. In light of the fact that a post-energy crisis recorded year, 2003, is available for analysis, for accounts affected by the energy crisis, it is reasonable to exclude the recorded data affected by the energy crisis for forecasting purposes. It is simpler than attempting to identify and add or subtract energy crisis-related adjustments in order to normalize expenses for that year or years.

We will adopt DRA's estimate of $6,366,000 for Account 923.

Regarding 2003, while SCE has identified potential issues that may increase its costs above 2003 recorded level, it has not quantified those costs. Also, the record does not substantiate that all 2003 recorded activities are necessarily ongoing through the test year. Cost for new activities may be offset by the effect of one-time or nonrecurring costs in 2003 not being incurred in the test year.

Regarding DRA's adjustment to Account 928 to remove costs incurred in 2003 for the Gas Border Price Investigation, SCE argues that this investigation is representative of the type of Commission regulatory proceeding that SCE participates in regularly on behalf of its ratepayers. Also, SCE states that the investigation is ongoing and expects to incur related costs in 2006. SCE's explanation is reasonable, especially in light of the fact that DRA's further adjustment would reduce expenses for Account 928 significantly below any of

the recorded amounts for the years 1999 through 2003. We will therefore use the unadjusted 2003 recorded amount of $1,846,000 to forecast the test year expense for Account 928.

15.32 Account 923 – Environmental Health and Safety, Non-Labor

SCE used a budget based method to forecast $980,000 for non-labor corporate EH&S expenses included in Account 923. SCE states that the last recorded year plus new incremental expense is the most accurate approach to estimating the cost of the new programs that are being developed. SCE further states that it did not use the five-year average method because two of the years were highly anomalous as a result of the energy crisis, skew results of the average and grossly under-fund this account.

DRA used a five-year average of $172,000 to forecast this account. DRA believes the average captures the cyclical nature of the account and provides a sufficient level of expense for the test year.

15.33 Discussion

In its prepared and rebuttal testimony, SCE supports its budget by identifying the following proposed consultant activities:

- $250,000 to update existing information management systems and communications materials to support regulatory compliance, public health and safety,
- $100,000 for its EMF group to provide Field Management Plans for new and existing public schools,
- $250,000 for Public safety to provide resources to develop electrical safety educational materials, thus supplementing existing programs and improving coordination of existing programs, and

- $208,000 for the Environmental Services and Consulting section to ensure compliance with endangered species requirements.

SCE's requested budgeted activities, totaling $808,000, appear reasonable and are discrete consultant activities. SCE has provided no information on what is embedded in the historic data and whether those consultant activities will continue through the test year. There is no justification for including the 2003 base year costs in the estimate. We will therefore adopt a test year forecast of $808,000 for the EH&S non-labor included in Account 923.

15.34 Account – ES&M Consultant Expense Forecast

SCE used a budget-based analysis to forecast the Account 923 test year consultant expense for ES&M activities, which amounts to $3,400,000.

DRA recommends that SCE's request be reduced to reflect the last recorded year's expenditures, because SCE has been unable to adequately justify its request for an increase over that amount. DRA recommends an amount of $2,607,000.

SCE argues that DRA's use of 2003 recorded is inappropriate because the recorded amounts used by DRA include refund-related consulting cost adjustments that are not forecasted to reoccur during the test year. The adjustments were one time refunds received – pursuant to FERC proceedings – from El Paso and Reliant. SCE states that it made these consulting cost adjustments because its consultants performed studies that contributed to the successful resolution of the proceedings against these companies on terms favorable to California. SCE also criticizes DRA for not taking into account the Commission's recent long-term procurement plan decision (D.04-12-048) that SCE believes will result in higher than forecasted consultant costs due to the

potential need for independent evaluators whenever a utility or a utility's affiliate participates in a utility procurement solicitation.

15.35 Discussion

While criticizing DRA's use of 2003 recorded information, SCE has provided little to support its test year consultant budget for ES&M. In its direct showing, SCE indicates the types of situations where consultants are used and the fact that its costs have been held to the $3,000,000 level for the past two years. SCE provides no detail on its budget, only indicating that due to ES&M's resumption of the procurement function in 2003, recent experience is more relevant for forecasting purposes. It was in rebuttal that SCE brought up potential costs related to D.04-12-048, which was issued after SCE prepared its testimony.

Other than potential independent evaluator costs, SCE has not justified its ES&M consultant budget request. The independent evaluator costs are speculative as it depends on the number of SCE/SCE affiliate bids that are submitted. Rather than use SCE's budget, we will instead use the 2003 recorded amount of $2,607,000 as the test year estimate. We will not adjust this amount to remove the affect of approximately $400,000 in refunds; because, based on the record, it is not possible to determine that other refunds or other reductions to 2003 recorded consulting costs of that magnitude will not occur in the test year.

15.36 Account – 923 – QF Resources, Consultant Expense

For QF Resources consultant costs, SCE used the 2003 recorded amount, increased by $224,000 to reflect future business needs. SCE's request amounts to $400,000.

DRA recommends no increase over the recorded 2003 amount of $176,000, because recent history does not reflect a return to spending at the level requested by SCE.

15.37 Discussion

In its direct testimony, SCE supports its request to more than double its consulting budget over the 2003 recorded level by citing an expected need for supplemental resources due to new renewable procurement activities and legislative and regulatory initiatives. SCE also cites the potential need for supplemental resources in the event of disputes, negotiations or litigation with QF contracts. While SCE provided a little more detail about potential activities in its rebuttal showing, there is nothing specific to support the reasonableness of the requested increase of $224,000. Also, SCE suggests that it is more cost-effective to contract on a short-term basis with outside consultants with the expertise to evaluate technical aspects of a study rather than to add a technical expert to its labor base. However, there is no evidence that shows that any such cost-effective analysis was done in determining the $224,000 incremental request. Finally, since specific consultant activities and costs are not identified for the base year, it is not possible to determine whether all recorded 2003 activities will continue through the test year. If embedded activities terminate before the test year, the associated costs can be used to fund other activities. For these reasons, we will use the last recorded expense level of $176,000 as the test year forecast for QF Resource consultant costs included in Account 923.

15.38 Account 925 – Worker's Compensation Staff

For workers' compensation staff, SCE uses a budget based method to forecast an expense of $6,319,000 for the test year. SCE states that this method takes into account additional employees and medical management contractors

that are necessary to comply with the utilization review statutes and regulations as well as the guidelines of the State Office of Self-Insurance Plans.

DRA incorporates a five-year average method, to account for fluctuations during the 1999-2003 time period. This results in a test year estimate of $4,259,000.

15.39 Discussion

From 1999 through 2002, SCE recorded amounts ranging from $3,095,000 to $3,730,000 for this account. The recorded amount for 2003 was $7,324,000. SCE attributes the significant increase to increased costs for medical management contractors and the increase in the Self-Insurers Security Fund Payment. Compared to 2003, SCE added two additional employees and two additional medical management contractors during 2004. For the test year estimate, these adjustments are offset by a reduction in Self-Insurers Fund payment. DRA states that the 2004 unadjusted recorded amount for worker's compensation staff is approximately $5,700,000. DRA's use of a five-year average reduces the test year expense significantly below that needed to support existing staffing levels without providing convincing evidence regarding why it is prudent to do so.

SCE reasonably supports its test year estimate of $6,319,000 which we will adopt.

15.40 Account 925 – Workers' Compensation Reserve

For forecasting the Workers' Compensation Reserve, SCE uses a three-year average to take into account the increase in workers' compensation payment reserve expenses which commenced in 2001 and continued through 2003. SCE forecasts a reserve of $44,466,000 for the test year.

DRA incorporates a five-year average method, due to fluctuations during the 1999-2003 time period. This results in an estimate of $36,360,000.

TURN proposes that the test year forecast be set at 10% above the adjusted recorded 2004 reserve expense, or $30,779,000. TURN also proposes a two-way balancing account that would provide 90% recovery for any amounts within plus or minus 30% from the forecasted amount. The 90% figure is intended to balance any forecasting inaccuracy under current conditions. TURN also proposes that Nuclear MIP reserve expenses transferred to Account 528 should be excluded when computing the balancing account results.

15.41 Discussion

The recorded-adjusted workers' compensation reserve expenses for the year 1999 through 2004 are as follows:

1999	$27,299,000
2000	$21,171,000
2001	$31,162,000
2002	$43,596,000
2003	$58,640,000
2004	$27,981,000

Subsequent to providing TURN with the recorded 2004 amount, SCE determined that the figure does not include the Claims Division expenditures, which on average amount to approximately $9,500,000 per year. If that amount were added to the $27,981,000 recorded amount for 2004, the total would be about $38,500,000.

In its prepared testimony, SCE states:

> Our test year 2006 reserve expense forecast is expected to be lower than our 2003 recorded, based upon using a three-year average. Due to the current changes in workers' compensation regulations, SCE foresees lower expenses than 2003 recorded but does not believe future expenses will return to 1999-2000 levels. Although no

> one can forecast exactly what the future expense will be, SCE believes that a three–year average would be the most accurate estimate at this time.[68]

Recorded 2004 data substantiates that the test year expense will likely be less than the 2003 recorded amount. The extent to which it will be below 2003 recorded is at issue. SCE uses a three-year average, DRA uses a five-year average and TURN uses 2004 recorded increased by 10%.

TURN points out that 2004 data represents the only time frame subsequent to the passage of Senate Bill (SB) 899, and recommends that such data be used due to significant known changes in circumstances. DRA also points to the enactment of Assembly Bill 227, SB 228 and SB 899 as reasons to expect lower workers' compensation costs in the test year.

TURN also points out that even though benefit levels increased by 20% from 2003 to 2004, the amount of the benefits paid declined by 14.7% and was almost the same in 2004 as 2003. Also, even though benefit levels increased by another 15% from 2004 to 2005, and the number of claims jumped 60%, the benefits paid out remained unchanged from first quarter 2004 to first quarter 2005.

SCE argues that DRA's five-year average estimate of $36,360,000 is inappropriate, because 1999 and 2000 are not representative of test year expenses. While that may be true, it also appears that recorded 2003 data is not representative of test year expenditures. An average of 2001 and 2002 recorded data results in an amount of $37,379,000, which is not materially different from the 2004 recorded amount of $38,500,000 that includes an approximation of

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[68] SCE, Exhibit 71, p. 63.

Claims Division expenditures or from DRA's estimate that includes high and low expenditures. Based on our discussion above, we will adopt $37,379,000 as a reasonable test year forecast for workers' compensation reserve expense.

As stated earlier, the adopted amount is close to that recorded in 2004. To a certain extent, 2004 reflects recent workers' compensation reforms. We will not prejudge potential legislation that may increase costs. Also, we do not see a necessity for a balancing account as proposed by TURN in its prepared testimony and modified in its reply brief.[69]

15.42 Account 925 – Environmental Health and Safety, Corporate Safety

SCE used a budget based method to forecast $1,491,000 for corporate safety expenses. SCE states that the last recorded year plus new incremental expense is the most accurate approach to estimating the cost of the new programs that are being developed. SCE further states that it did not use the last recorded year method, because the method does not consider the need for additional programs to help prevent work-related injuries.

DRA used the last recorded year amount of $967,000 to forecast this account. Recorded 2003 data reflects the highest level of expenditures over the last five years, and DRA believes that amount should provide sufficient funding for SCE's test year requirements.

15.43 Discussion

DRA correctly recognizes that the 2003 recorded amount of $967,000 is higher than any of the expenses in the years 1999 to 2002, which ranged from

[69] In its rely brief, on page 11, TURN modified its balancing account proposal to cover 100% of the recorded costs as opposed to the 90% proposed in its original testimony.

$760,000 to $953,000. This indicates a general increase in corporate safety costs, which is generally reasonable and may be desirable if employee safety is enhanced. However, SCE proposes a $524,000 increase (54%) in this account over the 2003 recorded level based on its budget method. SCE's use of 2003 recorded data and budgeted incremental costs for new programs does not consider possible cost reductions either for recorded activities that may be replaced by new programs or productivity improvements that may reduce existing costs. We will specifically include labor expense of $228,000 for developing a Corporate Safety Center of Excellence for the prevention of sprains and strains which account for about 50% of all work place injuries. We will also include $70,000 in non-labor expenses. We will not include $226,000 in labor expense budgeted to improve SCE's ability to track safety performance measures. We will assume that if truly necessary, such activities can be funded from that part of the unspecified budget that is based on the recorded 2003 expense level. We therefore adopt a test year forecast of $1,265,000 for the corporate safety activities in Account 925.

15.44 Account 926 – Pension Costs

For test year 2006, SCE forecasts a total of $51,159,000 for pension costs. SCE states that its contributions for pensions include normal cost plus amortization of liabilities for ad hoc cost of living adjustments and various reserves, and that its current funding policy has been in effect since at least 1982.

DRA explains that SCE's forecast is based upon determinations made by SCE's retirement plan actuary using 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. SCE's forecast is a three-year average of the Rate Recovery

Allowance amounts, assuming quarterly payments. In response to a data request, SCE provided its actuary's calculations for the ERISA minimum contribution, which fluctuates depending on which year the credit balance is used. In the interest of reducing costs to ratepayers, DRA recommends using the credit balance in 2008, which results in the lowest contribution amount -- a three-year average of $46,109,000. DRA asserts that there is no rationale for ratepayers to fund above a level necessary to keep the pension fund sustainable.

In rebuttal, SCE argues that DRA's minimum funding proposal should be rejected as unwise policy particularly in today's environment in which pension underfunding is a significant public policy issue. SCE also provided information that indicates that the ERISA minimum cost calculation, as proposed by DRA, should be updated and would now result in a three-year average pension cost of $48,690,000.

15.45 Discussion

First of all, we will consider the ERISA minimum cost to be $48,690,000 rather than the $46,109,000 shown in DRA's testimony. Both costs were calculated by SCE's actuary. SCE states that the update better reflects all of the available IRS guidance on the application of the SCE Retirement Plan's funding method in the development of minimum required contributions. The revision was based on a review of IRS guidance starting with information received at the annual Enrolled Actuaries' meeting held during April 4-6, 2005, in the form of written responses from the IRS to questions submitted by actuaries. DRA objects to the updated number pointing out that the guidance provided by the IRS at the meeting was accompanied by a caveat that it does not necessarily represent the positions of the Treasury or the IRS and cannot be relied upon by any taxpayer for any purpose. SCE explains that the IRS requires this caveat,

which gives it the flexibility to change its position and gives taxpayers less ability to rely on it when dealing with IRS. SCE's update and explanation are reasonable.

DRA proposed a minimum funding method in SCE's last GRC. The Commission rejected the proposal, stating in part:

> 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.[70]

In that proceeding there was a large difference between SCE's requested $31,450,000 and DRA's recommendation of $0. SCE contended that DRA's method was not usable either for ERISA minimum funding purposes or for IRS tax deductibility purposes. DRA's method in that case could be interpreted then to be neither sufficiently conservative nor in line with actuarial practice. In this proceeding, that appears not to be the case. The difference between the results of SCE's normal cost calculation of $51,159,000 and the results of the ERISA minimum cost calculation of $48,690,000 is $2,419,000, which is not substantial. The ERISA minimum calculation could therefore be considered sufficiently conservative. Also the calculation was performed by SCE's actuary, so it appears to be in line with actuarial practice.

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[70] D-04-07-022, *mimeo.,* pp. 219-220.

At this point, we are not prepared to specify the method for estimating future GRC pension costs. However for this proceeding, since our concerns expressed in D.04-07-022 have been alleviated, we will adopt DRA's proposal to reflect the ERISA minimum calculations in forecasting pension costs. The ERISA minimum calculations will maintain the funding necessary to protect employees from an insolvent pension fund. Under current circumstances, we will not require SCE's ratepayers to fund more than that. The adopted funding level for SCE's pension plan is $48,690,000.

We also adopt SCE's unopposed proposal to establish a two-way balancing account for pension costs, beginning with the 2006-2008 forecast period. The balancing account should record the difference between actual and forecast costs and should be amortized beginning in 2009. Any accumulated balance should receive interest at the commercial paper rate, consistent with treatment of interest accruals for other SCE balancing accounts.

15.46 Account 926 – 401(k) Savings Plan Design

In its prepared testimony, DRA opposed a step in SCE's calculation of the 401(k) Savings Plan. That step escalates the projection factor in 2005 to allow for an anticipated increase in costs related to plan changes. DRA indicated that SCE did not identify how the additional escalation factor correlated to the anticipated increase in costs related to the plan change and recommended excluding the additional escalation factor in calculating the plan costs. This resulted in a $13,958,000 difference between SCE and DRA. However, in its opening brief, DRA states that SCE has since provided supporting calculations, and DRA no longer opposes SCE's 401(k) adjustment. We therefore adopt SCE's 401(k) Savings Plan calculations.

15.47 Account 926 – Executive Benefits

SCE used a budget based method to forecast expenses of $15,020,000 in this account. SCE states that the executive benefits forecast recognizes and accrues what the required expenses, as determined by its actuaries' use of Generally Accepted Accounting Principles. SCE also states that the design of the executive retirement and survivor benefit plan has been unchanged since 1995, when the plan configuration was revised to reduce costs by eliminating post-retirement survivor benefits for executives and reducing their pre-retirement survivor benefits.

DRA used a four-year average of $8,574,000 to normalize 2003 expenses, and then applied SCE's pension and benefit escalation rate, resulting in a test year estimate of $10,647,000. DRA asserts its approach is reasonable because it normalizes the extraordinarily high 2003 costs and brings SCE executive benefits compensation more in line with the executive benefits provided by other companies.

15.48 Discussion

DRA apparently did not analyze the actuarial valuation of executive benefits, but rather relied on historical data and projected escalation factors. SCE argues, perhaps correctly, that DRA's four-year average of 1999-2002 data is flawed, because the costs in some of those years were significantly affected by the energy crisis. However, by 2003, salaries and bonuses had returned to normal levels.[71] Therefore, rather than our evaluating the accuracy of the actuarial valuation, it would be reasonable to escalate the 2003 recorded amount of $11,157,000 to the test year level. This method assumes no significant changes

[71] SCE, Exhibit 101, p. 60.

to the plan and no changes in the number of eligible executives and results in an adopted estimate of $13,855,000 for executive pensions and benefits.

DRA's concern regarding executive benefits, as it relates to those for other companies should be addressed in the context of the Total Compensation Study.

15.49 Account 927 – Franchise Fees

SCE uses a factor of 0.8930% to calculate test year franchise fees. The factor is a weighted three-year average (2006 – 2008) that considers increases in franchise fees paid to the Counties of Los Angeles and San Bernardino during the three-year rate case cycle. SCE states that this method normalizes the change over the GRC cycle ensuring that ratepayers are not overcharged and that SCE shareholders do not absorb all the expense increases.

DRA recommends a franchise fee factor of 0.8737 for the test year forecast, because it properly reflects the 2006 franchise requirements.

15.50 Discussion

DRA apparently opposes normalization of the franchise fee factor over the three-year GRC cycle. SCE's use of a weighted average for the three-year period, attempts to develop a single franchise fee factor that, over the three-year rate case cycle, will provide recovery of anticipated franchise fees, including those related to franchise fee factor increases that will likely occur during 2006. Those increases are due to the expiration of the current agreements with San Bernardino on June 13, 2006 and Los Angeles on December 27, 2006. Both counties have a statutory right to a payment based on either 2% of SCE's gross annual receipts arising from the use, operation, or possession of the franchise or 1% of SCE's gross annual revenues derived from the sale of electricity within the county limits, whichever calculation is greater. SCE

indicates that 1% of its gross receipts would provide the greater payment and would significantly increase the franchise fee payments to both counties. While the three-year average overstates the probable factor for 2006, it understates the probable factors for 2007 and 2008. That is the nature of cost normalization over multiple years. SCE's method is reasonable and its proposed franchise fee factor of 0.8930% will be adopted for this GRC cycle.

15.51 Supplier Diversity, Workforce Diversity, Corporate Transparency and Executive Compensation

Greenlining has raised issues related to corporate governance, good corporate citizenship, philanthropy, management diversity, supplier diversity, corporate transparency, executive compensation, and cost cutting.

15.51.1. Greenlining's Proposal

In Greenlining's opinion, SCE has, at best, an average record in some of the categories and a below average record in others. In summary, Greenlining proposes the following:

1) SCE be urged, but not ordered, to demonstrate its commitment to supplier diversity by honoring its 1989 GO-156 commitment to supplier diversity of 22.5%, a commitment filed with the CPUC and reached with the Greenlining Institute;[72]

2) SCE consider the importance in our diverse society of greater opportunities in upper management for Latinos and Asian Americans, as it committed to in its 1989 agreement with the Greenlining Institute. Edison has already

[72] Edison is presently at 16%, versus 23% for SBC.

demonstrated this leadership with regard to African Americans;[73]

3) SCE recognize the importance of philanthropy, particularly in the context of multi-million dollar executive compensation packages, with a special focus on underserved communities;[74]

4) SCE put on notice that top executive compensation, even if technically absorbed by the shareholders, directly affects ratepayer costs (since unions now carefully monitor top executive compensation packages,[75])

5) SCE consider linking large top executive bonuses ($73 million over the last three years to the top 30 executives) to issues of concern to this Commission, including philanthropy to the poor, supplier diversity, management diversity and quality consumer services, and

6) SCE be ordered to provide full executive compensation transparency, as provided by PG&E. Also, as a condition of its next GRC, SCE should be required to provide full transparent and understandable information on the present and future market value of retirement severance benefits of its top executives.

Greenlining states that it is not asking the Commission to take any punitive actions regarding SCE on any of the above mentioned issues. Instead, it urges the Commission to highlight Edison deficiencies, highlight the

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[73] Ten African Americans are included among the top 100, versus only four Latinos and four Asian Americans.

[74] In 2004, only $1,300,000 in philanthropy was given by Edison to the poor, versus $10,300,000 in compensation given to SCE's CEO.

[75] Unrefuted evidence by Greenlining expert Michael Phillips, Exhibit 501, pp 13-15.

direction that this Commission is going in regard to these matters, and urge Edison to be a leader in these areas.

15.51.2. SCE's Response

Regarding supplier diversity, SCE notes that a 22.5% supplier diversity goal for Minority Business Enterprises (MBEs) is not only higher than the GO 156 collective goal of 21.5% for Women, Minority, Disable Veteran Business Enterprises (WMDVBEs), but also unreasonable given the Commission's decision to eliminate exclusions. SCE foresees capital expenditures in the near future where there are no minority suppliers because the company will be purchasing large components of transformers, wire, cable, and wood poles directly from existing manufacturers. Since these components are no longer excluded from the base used to determine the utility's supplier diversity percentage, SCE believes that a 22.5 % goal for MBEs, as proposed by Greenlining, is unrealistic.

Regarding workforce diversity, SCE testified that it recognizes the need to make solid progress in the area of workforce diversity, especially in the top 500 positions. In this regard, SCE has a diversity strategy in place that includes focused recruiting strategies as well as internal programs, such as the company's Leadership Programs, that provide the company with a more diverse internal pool of candidates.

Regarding philanthropy, SCE states that it has made a philanthropy goal of 1% of pre-tax income with 60% going to nonprofit and community based organizations that support the underserved community. It is SCE's position that this should appropriately be left to the discretion of SCE since the company's cash contributions are funded by EIX's shareholders and therefore should not be mandated by the Commission.

Regarding Greenlining's recommendation to tie executive bonuses to philanthropy, SCE states that the Commission has previously rejected a similar proposal and nothing new has occurred that would justify a change in the Commission's decision. SCE further states that Greenlining's new proposal to link executive bonuses to supplier diversity and workforce diversity, which was not discussed in testimony or hearings, is vague and unsubstantiated. It is SCE's position that the Commission has previously rejected Greenlining's attempt to link executive compensation to philanthropy and should likewise reject Greenlining's attempt to link executive compensation to either supplier diversity or workforce diversity.

Regarding Greenlining recommendations related to corporate transparency, SCE states that the issue of reporting requirements for executive compensation has been addressed by the Commission in R.03-08-019 and does not need to be addressed in this proceeding.

15.51.3. Discussion

During the proceeding, Greenlining provided a copy of its annual supplier diversity report for major utilities regulated by this Commission. The 2004 report, rates utility efforts with respect to contracting practices with MBEs.[76] With 16.4% of its contracts going to minorities, SCE ranked 5th with a C+ rating.[77] When compared to SBC's A- rating and the B rating for both SoCalGas and SDG&E, SCE's efforts are barely adequate. We urge SCE to increase its

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[76] *See* Exhibit 506.

[77] For comparison, SBC ranked 1st with 23.0% and an A- rating, Southern California Gas Company ranked 2nd with 17.7% and a B rating, SDG&E ranked 3rd with 17.4% and a B rating, AT&T ranked 4th with17.2% and a B rating, Verizon ranked 6th with 15.2% and a C+ rating, and PG&E ranked 7th with 11.1% and a D rating.

efforts in this area, and will look favorably at performance and ratings that demonstrate greater SCE leadership in contracting with minorities. Consideration of the 1989 22.5% contracting goal for MBEs, even though the conditions regarding exclusions have changed, would be a significant step in that direction. While utilization of MBE suppliers may be dependent on the utilities' needs and the availability of MBE vendors to fulfill those needs, the variance in MBE utilization between utilities does suggest that there may be MBE opportunities that some utilities are overlooking. Practices and plans related to the utilization of WMDVBE suppliers are the subject of annual utility and Commission reports required by GO 156. If potential improvements in supplier diversity can be identified through this process, they should be considered for implementation.

In its opening brief, Greenlining proposes that SCE be required to track its supplier diversity achievements for small and medium sized minority businesses and to report to its CEO and top management the dollar amount of its supplier diversity that is awarded to minority owned businesses with revenues of $10,000,000 or less. As a threshold matter, SCE states that small and medium sized minority businesses are not a vendor category recognized by the Commission in GO 156. However, SCE has voluntarily agreed to analyze this type of data as part of the Company's efforts on the California Utilities Diversity Council. SCE states that it has not yet been established that this kind of analysis would necessarily lead to enhanced minority owned businesses, nor is it part of the Commission's GO 156 guidelines. Therefore, SCE argues that it should not be required to report its supplier diversity achievements for small and medium sized minority businesses. We appreciate SCE's cooperation in voluntarily providing the requested information, but for the reasons suggested by SCE will

not establish a requirement to do so. If deemed appropriate, such a requirement can be developed generically, in the future.

During the proceeding, Greenlining developed information that showed among SCE's top 100 managers, 10% were African American, 4% were Latino and 4% were Asian American. While Greenlining commends SCE for its achievements regarding African Americans, it criticizes that for Latinos and Asian Americans whose population is larger than that of African Americans by six times and two times, respectively. We agree in both respects. SCE has shown that it can achieve significant African American representation in its management through internal development and outside hiring. SCE also recognizes the need to make solid progress in the workforce diversity and cites its strategies and programs to do so. We urge SCE to immediately implement such mechanisms to increase the representation of Latino and Asian American managers and look forward to seeing the results of its efforts. As part of its next GRC filing, SCE should provide information on its workforce diversity achievements, similar to that provided by Greenlining in Exhibit 505.

During the proceeding, Greenlining developed information that compared SCE's philanthropy to bonuses to top executives. For example, in 2004, while bonuses to the CEO amounted to approximately $8,700,000 and bonuses to the top 30 executives amounted to approximately $30,200,000, SCE's philanthropy consisted of $80,000 to African Americans, $237,000 to Latinos, $142,000 to Asian Americans, and $1,266,000 to the poor. According to SCE, it has committed to a philanthropy goal of 1% of pre-tax income with 60% going to nonprofit and community based organizations that support the underserved community. While Greenlining would commend that goal, it urges SCE to consider President Peevey's urging of utilities to develop strategic

long-term philanthropic programs where cash philanthropy equals or exceeds 2% of pretax profits and at least 80% is committed to underserved and poor communities.

For many reasons, including good corporate citizenship, social responsibility, and public perception, philanthropy is an important consideration for SCE/EIX and corporations in general. However, as we have previously indicated, we have no jurisdiction to order a change in SCE's giving practices.[78] Instead, we urge EIX/SCE to give due consideration to President Peevey's stated opinions and preferences in this area when determining its philanthropic goals.

In D.04-07-022, for purposes of ratemaking, we declined Greenlining's attempt to link SCE's executive compensation package to its philanthropy. We stated that link was not supported by any study and was without merit.[79] After consideration of the record in this proceeding, we again find no support for linking philanthropy and executive compensation and will not do so.

With respect to linking executive compensation to supplier diversity, workforce diversity, or quality consumer services, we note that to the extent that executive compensation is reflected in rates, it has been justified through the total compensation study that is included as part of the record in this case. For that reason, we will not establish those direct links. However, in order to enhance its efforts in these areas, we encourage SCE to consider the inclusion

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[78] *See* D.04-07-022, Section 6.7.2.2.3.

[79] *Id.*

of supplier diversity, workforce diversity and quality consumer service results in determining incentive compensation for the responsible employees or executives.

Greenlining also asserts that ratepayers bear the cost of excessive executive compensation, particularly when unions take such compensation into account during bargaining with top management. We will not adjust any costs or make any policy decisions based on that assertion. It would be speculative to attempt to quantify any associated ratepayer costs. Also, the total compensation study can put possible cost increases into perspective. As stated previously, as a whole, SCE total compensation is within market and is reasonable. We also note that, in this decision, we have allocated certain compensation costs between shareholders and ratepayers. We see no reason to further consider Greenlining's assertion.

Finally, Greenlining requests more transparency in the reporting of executive compensation, specifically in the form that PG&E currently reports as a result of the applicable requirements in D.04-05-055. Such transparency is crucial when determining the reasonableness of executive compensation. For purposes of the General Order 77-L report, SCE should follow the PG&E model for reporting executive compensation. Also, in its next GRC, SCE should provide full transparent and understandable information on the present and future market value of the retirement severance benefits of its top executives.

16. Depreciation

16.1. SCE's Request

SCE's depreciation rates for transmission and distribution (T&D) accounts have not been updated since its 1995 GRC. SCE asserts that these rates are out of date and the accumulated depreciation deficit is growing each year. SCE estimates that the current T&D depreciation rates have resulted in

accumulated depreciation that is approximately $1.4 billion behind where depreciation rates would be based on current authorized levels of net salvage.

Accordingly, SCE requests that the Commission adopt its proposed depreciation expense of $934,800,000 for 2006 which represents a $238,300,000 or 34% increase over the authorized level in year 2003. The largest contributor to the increase is the recovery of SCE's past deficit in accumulated depreciation.

According to the company, its request is fully supported by its depreciation study, which was conducted in accordance with the Commission's Standard Practice U-4, Determination of Straight Line Remaining Life Accruals - a methodology used by this Commission for over 50 years. In conducting its study, SCE indicates that it performed a thorough analysis of its accounting records, drew upon the observations and expertise of field personnel with many years of operations experience, and applied the collective judgment of depreciation experts with many years of experience.

16.2. DRA's Recommendation

DRA also conducted its analysis of depreciation rates in accordance with the procedures set forth in Standard Practice U-4. DRA agrees with SCE's proposed average service lives. However, DRA disagrees with SCE's net salvage analysis. DRA's estimates for net salvage are about $101,000,000 less than SCE's for three reasons: (1) DRA is proposing a number of adjustments to SCE's requested capital additions for the test year, (2) SCE used 10 years of historical data as the basis for calculating its proposed net salvage ratios, while DRA primarily used 15 years of historical data, and (3) DRA recommends that the increase in negative salvage rates be capped at 25% above current levels for FERC Accounts 364 and 369.

DRA provides four reasons why using 15 years of historical data is more appropriate than using 10 years. First, a 15-year band provides a more accurate and balanced picture of transactions occurring over a greater time period. Second, a 15-year band is consistent with the 15-year historical band associated with the depreciation study SCE performed in its last GRC. Third, a 15-year band in this case is consistent with the 15-year historical bands used by both SDG&E and PG&E to perform their depreciation studies in their last GRCs. Fourth, a 15-year band, in contrast to a shorter time frame, mitigates the adverse impacts on ratepayers.

For Account 364, poles, towers and fixtures, DRA's 15-year historical average results in a net salvage rate of -190%. This contrasts with SCE's requested net salvage of -250% and the currently authorized rate of -100%. Account 364 consists of approximately $857,000,000 of investment and represents the most significant portion of the increase associated with net salvage in this case. Under SCE's proposal the company would recover approximately $2.1 billion in future negative net salvage costs above the $857,000,000 over the remaining lives of the assets. Because of the potential size of revenue requirement increase, DRA urges the Commission to cap the increase in order to mitigate the impact on ratepayers. Under DRA's recommendation the negative net salvage rate of 125% would provide approximately $1.1 billion over the remaining lives of the Account 364 assets.

Similarly for Account 369, services, which consists of approximately $752,000,000 of investment, the currently authorized net salvage rate is, -60%, SCE requests a rate of -100% and DRA recommends the rate be capped at -75%. Over the remaining lives of the Account 369 assets, SCE's proposal would result

in negative net salvage costs of $752,000,000, while DRA's recommendation would result in costs of $564,000,000.

16.3. TURN's Recommendation

As background to its recommendations, TURN provided the following:

- The Financial Accounting Standards Board (FASB) has issued Statement of Financial Accounting Standard (SFAS) 143 and, in doing so, changed the financial reporting requirements for retirement obligations. Where the entity has a legal obligation to remove an asset, it has an "asset retirement obligation" or ARO for which it must capitalize the discounted "fair value" and depreciate that amount as a component of the original asset cost. SFAS 143 reminded regulated entities such as Edison that the treatment of retirement obligations that did not meet the definition of an ARO might still meet the requirements of SFAS 71 for reporting as a regulatory liability.
- Concurrent with its implementation of SFAS 143, Edison reported a regulatory liability for its costs of removal for such non-ARO assets. In doing so, Edison acknowledged that under present ratemaking practices the Commission expects these costs to be incurred in the future and, to the extent they are not, understands that "future rates will be reduced by corresponding amounts."[80] But at this point the Commission's expectation and understanding appear to be implicit; certainly Edison did not point to any specific Commission decision that explicitly set forth such an expectation and understanding.

[80] SFAS 71, ¶ 11(b).

- Under Edison's current depreciation rates, the non-ARO regulatory liability grew by $90 million in 2004, to reach a total of $2.112 billion at the end of that year. If the Commission approves Edison's requested depreciation rates, it can expect this non-ARO amount to grow even more rapidly in 2006 and beyond.

16.3.1. Explicit Recognition of SCE's Non-ARO Liability

According to TURN, in past years SCE has collected in rates several billion dollars based on the expectation that it will spend those amounts at some point in the future for the costs of removing assets that will be been retired. TURN expects this pattern to continue for the foreseeable future; that is SCE will collect in current rates an amount for costs of removal that far exceeds the current removal costs, with the excess intended to recover removal costs that are expected to be incurred in the future.

Prior to the enactment of SFAS 143, the full amount of the amounts collected-for-but-not-yet-spent-on removal costs appeared as an undifferentiated amount of "accumulated depreciation" on SCE's financial statements. SFAS 143 distinguished between removal activities that companies were legally obligated to undertake, and those that were not compelled by any such legal obligation. The former were deemed AROs and, while amounting to a substantial past and ongoing expense for SCE's customers, AROs are not the subject of TURN's dispute.

According to TURN, when FASB issued SFAS 143, it concluded that asset retirement costs that are not associated with an ARO might still warrant treatment as a regulatory liability "if the requirements of Statement [of

Financial Accounting Standards No.] 71 are met."[81] In recent years, SCE has reported a regulatory liability for its accumulated depreciation amounts associated with plant removal costs that do not meet the definition of an ARO (non-ARO). TURN argues that with this action SCE has demonstrated its determination that the requirements of SFAS 71 are indeed met for those costs.

TURN recommends that the Commission explicitly recognize, for ratemaking purposes, the regulatory liability associated with the non-ARO accrual. TURN asserts that, given the amount at stake and that such recognition is already implicit (as evidenced by the regulatory liability created for financial reporting purposes), the Commission should make such explicit recognition and eliminate any future doubt or dispute about the ratemaking treatment of the non-ARO balance.

TURN acknowledges that there probably is very little risk that anything will occur over the next years and decades that would jeopardize ratepayers' interest in the funds collected to date, as well as those collected going forward, for the costs of removing SCE's utility assets. But given how high the stakes are, and how relatively easy it is to mitigate, if not eliminate, the risk, TURN asserts that the Commission should make explicit the obligation to either spend the funds on costs of removal or return the balance to ratepayers.

TURN notes that asset removal costs are just one of several examples of costs funded in current rates even though the utility is unlikely to incur those costs until many years in the future. TURN specifically argues that just as the Commission directed the establishment of a Post-Retirement Benefits

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[81] Exhibit 348 (Majoros Testimony for TURN), p. 10, citing SFAS 143 ¶ B73.

Other than Pensions (PBOP) regulatory asset for regulatory accounting purposes after SFAS 106 was implemented, it should recognize the non-ARO regulatory liability for regulatory accounting and ratemaking purposes.

16.3.2. Reporting Requirements

TURN also recommends that SCE separately identify and report non-ARO costs of removal in all future reports, rate cases, and depreciation studies. According to TURN, this is consistent with the separate subsidiary records the utility is required to maintain for the purposes of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals. TURN notes that (1) SCE's witnesses stated that they would not oppose such a separation of the utility's depreciation showing between plant recovery and cost of removal collection; (2) such a showing should require minimal additional effort, since SCE already maintains a subsidiary ledger in this manner; and (3) the greater specificity will be more consistent with the requirements of SFAS 143 and FERC Order 631 and should provide an opportunity for improved regulatory analysis of these matters.

16.3.3. TURN's Analysis of SCE's Cost of Removal Proposal

Regarding SCE's proposal for determining costs of removal, TURN makes the following observations and criticisms:

- Nothing in SCE's depreciation study attributes any specific recorded increase in removal costs, much less any proposed increase in future removal costs, to any particular factor other than inflation affecting the associated labor and other costs related to that removal.
- Given that SCE's proposed depreciation rates are so driven by the forecast of future costs of

removal, which are in turn extremely dependent on assumptions about future inflation, the Commission must require a demonstration of the reasonableness of the future inflation assumptions. In preparing a forecast of future costs of removal, the utility should attempt to use information that it believes is going to be the most accurate in terms of what the actual cost will be at that point in the future when the cost is incurred.

- SCE failed to make any attempt to develop an accurate inflation rate for use in its forecast of future costs of removal. Instead, it calculated ratios for plant installed decades in the past, a process that means the ratios reflect the level of inflation or cost escalation SCE experienced over those past decades. In other words, if the plant was originally installed in 1950 and removed in 2003, the inflation from 1950 through the present is reflected in the resulting ratio.
- The Handy-Whitman Index, a standard measure of cost escalation, indicates that the cost escalation experienced in the last 45 years averaged 5% per year. However, for the equivalent costs over the past 10 years, cost escalation is 2.82% per year on average. Also, in its 2003 GRC, SCE relied upon a forecast of future inflation of 2.65% over the life of its transmission and distribution equipment.
- SCE is seeking a rate increase of approximately $130 million attributable entirely to changed depreciation rates for plant in service as of 2003. Before the Commission finds such an increase reasonable, it must assure itself that the underlying calculations are valid. The fact that the calculations do indeed reflect the extrapolation of future net salvage costs based on retirements that, with rare exception, amount

to less than 10% of the plant in service, is cause for concern.

- SCE largely if not entirely ignores potential reductions to future removal costs from a number of improvement initiatives it is undertaking. Specifically, SCE's "infrastructure replacement program" has as one of its underlying goals the replacement of more utility equipment before failure, rather than at or after failure. The successful strategic targeting of replacements should reduce the associated costs of removal, due to lower labor costs and reduced inflation impact. The removal can be performed on a scheduled basis, thus minimizing the risk that the associated work will entail overtime or contract labor. Furthermore, the earlier removal of a piece of equipment will reduce the impact that inflation has on the removal costs for that equipment. Also, SCE is undertaking "process improvement initiatives" in its "Business Process Integration" program. SCE states that the improvements are "expected to yield cost benefits associated with replacement and removal costs." Yet nowhere are such benefits reflected in the costs of removal that underlie SCE's proposed depreciation rates. This failure to include such future costs reductions in the forecast depreciation rates is another reason for the Commission to reject the utility's proposed rates.

16.3.4. TURN's Cost of Removal Proposal

In its prepared testimony, TURN proposed a number of alternatives for determining future costs of removal for purposes of establishing depreciation rates for this GRC cycle. After considering the points raised in the utility's rebuttal and the record evidence developed during hearings, TURN recommends that the Commission adopt a net present-value based approach to

calculating the future costs of removal and, by extension, the net salvage ratios used to derive depreciation rates. Specifically, TURN recommends that the Commission determine the net present value in 2006 dollars of Edison's forecast removal costs, and then add to that amount a component intended to reflect inflation likely to be experienced during the rate case cycle. In the utility's next GRC, the Commission can compare the forecast inflation with the inflation the utility experienced and make any necessary adjustments on a going-forward basis. TURN submits that any error between a forecast of inflation and actual inflation over the next three or four years is likely to be far smaller than the error between forecast and actual over the next three or four decades.

TURN recommends that the Commission could leave the non-ARO regulatory liability as an offset to rate base for the time being, noting that should the SCE's depreciation accrual continue to grow at a rate that causes the Commission concern, it could consider in the future whether to amortize some or the entire amount of that liability.

16.4. SCE's Response

In response, SCE notes that neither DRA nor TURN object to SCE's depreciation life estimates. Their differences stem entirely from differences in net salvage estimates and methodologies.

16.4.1. SCE Response to DRA

SCE notes that DRA and the company agree on a number of significant issues:

- The methodology used for depreciation rates – *i.e.,* the Commission approved straight-line remaining life method;
- The depreciation life estimates;

- The depreciation levels for 89 of the 101 plant categories, including various coal;
- Hydro, nuclear, T&D, and general plant accounts;
- Increased removal costs; and
- A need to increase the accrual for net salvage costs.

DRA took issue with SCE's net salvage proposals for 12 out of 18 T&D FERC plant accounts. According to SCE, DRA (1) skews its net salvage estimates by choosing a simple 15-year average in those transmission and distribution accounts where SCE's net salvage costs have been increasing, thus dampening the effect of recent increasing; (2) ignores net salvage cost trends unless they are decreasing; (3) fails to use plant-weighted averages, which gives undue influence to smaller retirements; (4) rounds to less negative (or more positive) net salvage estimates instead of using the 15-year average; and (5) limits the net salvage estimates to an arbitrary 25% increase in two distribution line accounts in order to mitigate the needed increase in the depreciation rate. SCE argues that DRA's approach is results oriented and has a negative effect on depreciation rates, especially on distribution line accounts, which comprises of about 85% of SCE's depreciation expense request. SCE's authorized composite rate for distribution lines is 4.35% compared with DRA's proposed 4.33% for these assets.

While believing that its proposal provides the best estimates at this point in time and are even a bit conservative, SCE understands that the Commission might decide to take a measured approach to addressing the required change in depreciation rates in order to reduce rate impacts. With that in mind, SCE would support the use of levels of net salvage costs that are less than those it proposed, but equal to or greater than the net salvage cost estimates

of DRA, as a good first step to establishing appropriate depreciation rates, understanding that these estimates will be re-evaluated in SCE's next GRC. Under this approach, SCE would support the following net salvage estimates as representing a reasonable middle ground between SCE estimates and DRA's proposed mitigation:

Account		SCE's Application	Compromise Proposal	DRA Proposal
	Transmission			
353	Station Equipment	-5%	0%	5%
354	Towers and Fixtures	-85%	-70%	-70%
355	Poles and Fixtures	-85%	-70%	-70%
356	OH Conductors & Devices	-95%	-80%	-80%
357	UG Conduit	-10%	0%	0%
	Distribution			
362	Station Equipment	-15%	-10%	-10%
364	Poles, Towers and Fixtures	-250%	-190%	-125%
365	OH Conductors & Devices	-120%	-110%	-100%
367	UG Conductors & Devices	-70%	-60%	-60%
368	Line Transformers	-10%	-10%	0%
369	Services	-100%	-90%	-75%
373	Streetlighting	-30%	-25%	-15%

16.4.2. SCE Response to TURN

16.4.2.1. Recognition of the Non-ARO Liability

SCE disputes TURN's recommendation that the Commission should explicitly recognize the non-ARO liability. According to SCE, SFAS 143 does not dictate how either legal AROs or non-AROs should be treated in ratemaking. SFAS 143 is a financial accounting requirement that deals with the identification, measurement, and recording of legal liabilities associated with retirements of tangible, long-lived assets like SCE's nuclear generating stations and is designed to standardize the way that companies report removal costs when there is a legal obligation to remove or dispose of an asset.

SCE states that FERC Order 631 did not change the accounting for non-ARO removal expenses. It recognizes SFAS 143 by amending FERC's Uniform System of Accounts to account for AROs. Like SFAS 143, it

adheres to existing accounting by allowing recognition of timing differences that may arise for rate-regulated entities. According to SCE, FERC expressly concludes that there is no fundamental reason to change accounting concepts for costs that do not qualify as legal requirement obligations (*i.e.,* non-AROs). SCE also provided examples of state commissions that, after evaluating the impact of using the mechanics of SFAS 143 and FERC Order No. 631 in rate-regulation to recover net salvage costs, agree with FERC on this issue.[82]

SCE points out that SFAS 143 is not the first instance for which SCE has recorded regulatory assets and liabilities to account for differences between ratemaking and financial accounting. SCE reports several regulatory assets and liabilities in its financial statements. SCE's largest regulatory assets include flow-through taxes, transition cost deferral of rate reduction notes, and its unamortized nuclear and coal investments. SCE states that its year-end 2004 financial statements, shows that the total amount of SCE's regulatory assets is about the same as the total amount of its regulatory liabilities.

It is SCE's position that financial reporting changes required by SFAS 143 do not affect the underlying regulatory economics of the retirement obligations, because the goals of ratemaking and those of SFAS 143 are not the same and require very different approaches. SCE states that while SFAS 143 prescribes the measurement of legal retirement obligations on the balance sheet to provide investors a better idea of a company's future legal asset retirement obligations, in ratemaking, proper depreciation principles are

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[82] SCE cites *Washington Gas Light Co.,* Case No. 7689, Maryland PSC, 1984 Md. PSC LEXIS 49 (1983); *PacifiCorp,* Idaho Public Utilities Commission Order No. 29385,

Footnote continued on next page

concerned with measuring the service value of an asset (including the future removal cost expenditure) used during an accounting period for purposes of determining a fair revenue requirement to charge ratepayers.

SCE also states that TURN overlooks the fact that the Commission already recognizes the entire accumulated depreciation as a liability (not just that portion related to non-legal AROs) and therefore offsets the rate base by that amount. SCE also argues that the Commission has exercised prudent regulatory oversight regarding differences between the amounts collected by a utility and the amount spent after utility plant is retired. To demonstrate this, SCE points to the case of the plant divestitures that took place as a result of industry restructuring. In 1998, when SCE divested its 12 oil-/gas-fired generating stations, the purchasers assumed the responsibility for the decommissioning. Consequently, the Commission ordered SCE to refund to ratepayers the full amount of accumulated depreciation through the gain/loss calculation, including those amounts collected for plant decommissioning. SCE states that there was never a risk of SCE "disappearing" with ratepayer monies. SCE also cites the divesture of its Fuel Oil Pipeline Facilities in 2003 (again the buyer assumed the future decommissioning obligation), the Commission directed SCE to return to electric utility ratepayers the accumulated decommissioning expenses that would not have to be spent. This amounted to a $39,700,000 refund to ratepayers.

Finally, SCE claims that TURN's proposal may unnecessarily limit the Commission's options. SCE witness Umbaugh explained:

2003 Ida. PUC LEXIS 173, *5 (December 2, 2003); and *Central Vermont Public Service Corp.,* Docket Nos. 6946 and 6988, Vermont PSB, 2005 Vt. PUC LEXIS 65, * 226-27.

> "I don't think it's an uncertainty that has been an issue in the past and shouldn't be a concern, because the Commission can always make the decision at some point in time as to how to treat it. To require it to be a refund today kind of locks them in and eliminates one of the options that they have essentially to continue to adjust future rates going forward. I mean they could also have decided that if the cost of removal turns out to be more than they've allowed, they could have a one-time surcharge rather than to spread that out in the future. I mean the Commission has alternatives available to it."[83]

16.4.2.2. Separate Identification of Removal Cost Depreciation

Regarding TURN's assertion that it is critical that the Commission require that SCE separately identify the accumulated depreciation and depreciation rates associated with non-ARO removal costs, SCE states that TURN is being unnecessarily alarmist in its appeal. SCE it already separately accounts for non-ARO removal costs within FERC Account 108, Accumulated Provision for Depreciation, in accordance with regulatory accounting requirements, and has disclosed these costs in the audited financial statements filed with the Securities and Exchange Commission in accordance with financial reporting requirements. SCE unbundles its depreciation rates to separately record its removal cost accrual component in order to support this accounting.

[83] SCE, Umbaugh, Tr. 25/2508.

16.4.2.3. TURN's Analysis of SCE's Cost of Removal Proposal

SCE asserts that it properly, even conservatively, reflected inflation in its cost of removal proposal. TURN's critique ignores the fact that the age of future retirements will be substantially older than past retirements (for example, future distribution overhead conductor will be about four times as old as the retirements for 1994-2003). Because of this, SCE's net salvage estimates reflect a substantial reduction in future inflation.

TURN also asked SCE's depreciation witnesses a series of questions regarding a hypothetical distribution pole example to suggest that SCE's net salvage ratios reflect past levels of inflation and do not appropriately reflect future expectations. According to SCE, what TURN failed to address in this line of questioning is SCE's actual net salvage estimates, which were based on judgments that considered the representative nature of the recorded retirements. Contrary to TURN's hypothetical, SCE's actual proposed net salvage ratio for distribution poles understates the impact of future inflation. Recent recorded net salvage costs (2000-2003) have amounted to $1,490 per pole (nominal dollars). Over the 36-year remaining life of the existing distribution pole investment, these costs can be expected to increase with inflation. However, SCE's proposed 250% net salvage ratio provides future cost recovery of only $1,340 per pole for the existing distribution pole investment. According to SCE, its proposal actually reflects a cost deflation.

16.4.2.4. TURN's Cost of Removal Proposal

SCE criticizes TURN's NPV proposal as a last minute tack-on to the number of alternatives contained in its original testimony where, according to SCE, there is less than eight lines of explanation on the NPV proposal and no discussion of its impact.

According to SCE there is a logic gap in TURN's NPV proposal. That is if the service value of the asset is to be adjusted to current price levels, then the future net salvage and the historical original cost should both be adjusted. Such a modification to TURN's NPV approach would require an adjustment to the historical cost of the asset. SCE also refers the computational problems associated with TURN's NPV approach, especially for mass property. A properly calculated present value approach would require, by vintage, the determination of the timing of widely dispersed future retirements, consistent with an account's survivor curve. SCE asserts that TURN's proposal fails to do this and more importantly, it also fails to include an annual interest accretion in its determination. According to SCE, the complexity of the calculation necessary to do the NPV method is little different from that of the SFAS 143 approach, which TURN's witness ultimately rejects as too complicated.

SCE notes that TURN attempted to remedy some of its flaws by revising the NPV approach in its Opening Brief by providing periodic updates, changing the discount year from 2003 to 2006, adding an inflation adjustment between GRC cycles, and so forth. However, SCE asserts that the revisions do nothing to solve the inherent problems underlying the NPV method. Also, NARUC points out other reasons why interest-rate methods like TURN's NPV approach should be rejected, including "problems of annuity mathematics" and "heavy accruals due to greater interest toward the end of a property's life [which] can produce wide differences between accumulated accruals and the cost being recovered if retirements occur only a year or two from the estimated time."

16.5. SDG&E's Response to TURN

For many of the same reasons given by SCE, SDG&E opposes TURN's recommendation that the Commission make explicit the understanding that amounts received by SCE in rates for future cost of removal must either be spent on such removal or returned to ratepayers. SDG&E states that it is neither necessary nor wise for the Commission to make such an unequivocal declaration.

Regarding TURN's proposal ratemaking treatment for cost of removal, SDG&E states that TURN's opening brief makes a series of factual and conceptual errors in its arguments in favor of deviating from the Commission's long-standing ratemaking treatment of the cost of removal, and then it virtually abandons all of if its own witness' alternative approaches and advocates an approach that was not sponsored by any witness. For many of the same reasons given by SCE, SDG&E asserts that TURN's proposal unreasonably shifts recovery of removal costs from current ratepayers to future ratepayers, and is inconsistent with other aspects of ratemaking.

In support of SCE's methodology for calculating cost of removal, SDG&E argues that SCE has used a reasonable level of future inflation in estimating future nominal removal costs. SDG&E claims that on an original-cost basis, more recently installed plant has a greater weight, so the result is more reflective of inflation in a more recent time period than the full average useful life. SDG&E states that contrary to TURN's claim that SCE used the average inflation over the past 45 years, the methodology used by SCE actually reflects average inflation over a much shorter period.

16.6. PG&E's Response to TURN

For many of the same reasons given by SCE and SDG&E, PG&E opposes TURN's recommendation that the Commission make explicit the

understanding that amounts received by SCE in rates for future cost of removal must either be spent on such removal or returned to ratepayers. PG&E states the Commission should recognize that removal costs are ratepayer funded and that any excess accruals should be considered as such, if and when excess accruals become apparent. In PG&E's opinion, while returning such funds to customers should not be precluded by retroactive ratemaking or other concerns, neither should it be mandated, without taking into account all possible shortfalls in collections or other pertinent factors. PG&E concludes that all of these issues are more appropriately addressed at the time the issues arise, not in the abstract in SCE's GRC.

For many of the same reasons given by SCE and SDG&E, PG&E opposes TURN's cost of removal recommendation. While recommending that TURN's proposal be rejected, based on the record in this case, TURN believes that in the future, technical and generic issues such as the alternatives proposed by TURN would be more effectively and efficiently addressed in a generic statewide proceeding, if at all. PG&E recommends that the Commission should establish as a future policy that it is generally not appropriate for this Commission to consider proposals by interveners for technical adjustments to generic ratemaking policy in individual utility general rate cases.

16.7. Discussion

16.7.1. Recognition of a Regulatory Liability

TURN's request that the balance of funds collected for cost of removal related to non-ARO assets be recognized as a regulatory liability for ratemaking purposes is reasonable and will be adopted. The balance of this asset is substantial, amounting to $2.1 billion as of the end of 2004. This balance is already recognized as a regulatory liability for financial reporting purposes.

SCE has not demonstrated any potential harm to the company. In fact, SCE indicates that in some ways the Commission already recognizes and treats such assets in the manner requested by TURN. SCE points to the Commission actions that refunded to ratepayers the decommissioning funds no longer needed for 12 oil/gas generating stations and the fuel oil pipeline, which were all divested. TURN acknowledges that these actions were consistent with the explicit recognition that it now requests. Formal recognition of our ratemaking responsibilities is a reasonable course of action and will establish regulatory certainty regarding ratemaking treatment and principles that all parties generally agree is appropriate.

SCE also argues that adoption of TURN's request might limit the Commission's options in dealing with unspent funds. We understand our options to be a refund through future rate reductions or payment of future costs with no corresponding effect on future rates.[84] There is some flexibility in these options. For example, the period over which the refund in rates should occur is

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[84] Statement of Financial Accounting Standards No. 71, Appendix C: Basis for Conclusions, Paragraph 79 (b) states: "A regulator can provide rates intended to recover costs that are expected to be incurred in the future. Paragraphs 38 and 39 illustrate that possibility. The resulting increased charges to customers are liabilities and not revenues for the enterprise—the enterprise undertakes to provide the services for which the increased charges were collected, and it is obligated to return those increased charges if the future cost does not occur. The obligation will be fulfilled either by refunding the increased charges through future rate reductions or by paying the future costs with no corresponding effect on future rates. The resulting increases in charges to customers are unearned revenues until they are earned by their use for the intended purpose."

left open. Even so, such limitations are not unreasonable when considering the magnitude of the asset balance that has accumulated, and which will be increased in the future, with ratepayer funding.

16.7.2. Reporting Requirements

Regarding TURN's request that the CPUC require SCE to separately identify the accumulated depreciation and depreciation rates associated with non-ARO removal costs, there is no issue. SCE already separately accounts for non-ARO removal costs within FERC Account 108, Accumulated Provision for Depreciation, in accordance with regulatory accounting requirements, and has disclosed these costs in the audited financial statements filed with the Securities and Exchange Commission in accordance with financial reporting requirements.

16.7.3. Cost of Removal

There are two considerations in determining what the appropriate annual accrual for net salvage (cost of removal and salvage) should be. One consideration is the details of the determination of the accrual. In this case, SCE and DRA provide showings that analyze recorded net salvage as a percentage of original cost and then determine and apply a factor to all such properties placed into service. Costs would be recovered over the remaining lives of the properties.

The second consideration is the state of the accumulated accrual as it relates to existing plant. That is whether, based on the most recent determinations and assumptions regarding annual net salvage accruals, sufficient funds will be recovered over the remaining lives of the existing assets to remove them when they are retired.

Regarding the details of the determination of the accrual, in the past, SCE and the Commission have relied on the historical relationship of recorded net salvage costs and recorded retirements to develop rates to apply to future plant additions. This is consistent with practices of many other state commissions. However, when projected net salvage become substantial, in some cases substantially exceeding the original cost of the associated plant, we also have a responsibility to determine whether past practices are consistent with producing the most reliable net salvage projections.

Both DRA and TURN criticize SCE for not demonstrating the reasonableness of the escalation implicit in its cost of removal estimates. There is reason for such concerns. Inflation is the primary reason for the significant increases in historic and projected costs of removal. Variations in assumed inflation over a plant asset's life can substantially affect the cost of removal accrual over that time period. Consider the following net salvage analysis for a distribution pole replacement.

Condition	Net Salvage Rate	Net Salvage Accrual Over 45 years	Annual Escalation Over 45 years
Current Net Salvage Rate	100%	$5,499	2.16%
DRA Proposed Net Salvage Rate	125%	6,874	2.67%
SCE Stipulated Net Salvage Rate	190%	10,448	3.63%
SCE Proposed Net Salvage Rate	250%	13,748	4.27%
SCE Calculated Net Salvage Rate	308%	16,937	4.75%

Assumptions:

$5,499 – Cost of Installation of new pole in 2005

$2,331 – Estimated Cost of Removal in 2005 dollars

$ 233 – Estimated Gross Salvage in 2005 dollars

$2,098 – Estimated Net Salvage in 2005 dollars

45 years – Expected and Actual Life of New Pole

There is an implicit annual escalation related to the accumulated net salvage in each of the conditions indicated in the table. For the currently authorized condition (100% net salvage rate), the table shows $5,499 would be accrued for net salvage over the 45-year life. This implicitly reflects an annual escalation increase of 2.17% when compared to the 2005 dollar estimate of $2,098. If escalation related to net salvage increases by an average of 2.17%/year for the next 45 years, the net salvage rate for account 364 could be left at 100%. However if escalation reflects the historical compounded rate of 4.75%, the net salvage ratio would have to be increased to 308%. As the net salvage rate increases, the implicit annual escalation likewise increases. In examining the results, none of the conditions result in an implied escalation that is absurd. While 2% may be low and 5% may be high, either number or anything in between is not out of a zone of reasonableness. TURN has pointed out that for the 1993- 2003 time period, the Handy Whitman Index estimates annual cost escalation of 2.82% for distribution pole related costs. However, whether that would be an appropriate average rate for the next 45 years is questionable.

We note that the record in this proceeding does not include a forecast of inflation over the next 45 years. We do not even know if such forecasts are even made. However, in its next GRC, SCE should, as part of its account-by-account analysis, analyze the effects of past inflation on its proposed cost of removal rates and justify the implicit inflation rates reflected in its proposed rates.

Regarding the state of the accumulated accrual as it relates to existing plant, SCE has provided evidence indicating that with its proposed net salvage rate for distribution poles included in Account 364, it would not accumulate sufficient funds to retire the existing poles, even if the removal costs

remained at recent recorded levels, unadjusted for inflation over the remaining lives of the existing poles. This supports the need for a significant increase in the net salvage rate, at least as it relates to distribution poles. However, there is not much of an explanation of why this situation is likely to occur. For instance, was it solely due to recent Commission decisions which held the net salvage rate constant or was it due to past understating of the net salvage rate due to methodological flaws? Depending on the cause, there may be more appropriate ways to account for the increased removal costs not covered by net salvage rates. In its next GRC, SCE should, as part of its account by account analysis, provide analyses similar to the one for distribution poles, which quantifies potential accrual deficiencies for the future removal costs of existing assets. SCE should provide an analysis of what is causing any likely deficiency. With that information, we can determine the proper course of action to address the deficiency.

We do note that despite the distribution pole situation described above, by the nature of the established methodology where SCE is paying off current removal costs, while rates are being collected to fund future costs that are much higher than current costs, the non-ARO balance, which is already over $2 billion, will continue to grow. At no time, in the foreseeable future will SCE be short funds to cover its removal or net salvage costs.

In that regard it is not urgent that this issue be definitively decided at this time. Due to the large dollars at stake, and the wide range of possibilities, we prefer to be conservative in adjusting net salvage ratios, rates or accruals. In general, DRA's use of the 15-year historical average accomplishes that. Also, SCE did not dispute that it has used 15 years of historical data in the past, nor did it dispute that both SDG&E and PG&E used 15 years of historical

data in establishing their current rates. Therefore, except for Accounts 364 and 369, we will use DRA's recommended net salvage rates based on the 15-year average.

Because of the additional information provided by SCE to support its request for Account 364, we will adopt its proposed compromise net salvage rate of -190%. SCE did not provide such information for Account 369, and again due to our preference to proceed in a conservative manner, we will adopt DRA's proposal to cap the increase at -75%.

TURN now recommends that cost of removal be determined using a net present value methodology that provides for updating the effects of inflation from one GRC to the next. The focus of the cost of removal issue has been in accounts such as wood poles where cost of removal and depreciation expenses determinations are subject to mass accounting where properties are continually being placed into service while others are being retired. PG&E's witness indicated that the accounting necessary under the NPV methodology for calculating net salvage costs, while more complicated than that under current procedures, could be done. However, it is not clear that, in the long term, the results using TURN's proposal would be significantly different from that derived using the traditional net salvage procedures. Assuming costs are fully recoverable under TURN's proposal, in the long term, the newer poles will be accruing lower removal costs than the older poles. However under mass accounting, it is not clear that the accumulated removal costs and subsequent rate effect would be significantly different than if the same annual removal cost were applied to all poles. We would prefer not to change the methodology for calculating costs of removal until we are convinced there is a need to do so, there is means to do so, and the means provide results that are meaningfully different

and appropriate. At this time, we are not convinced that the net present value methodology as proposed by TURN should be adopted.

The conservative measures for determining net salvage in this decision are not permanent. In the future, we expect a more thorough record in order to make more definitive decisions. In its next GRC, by whatever method SCE proposes to estimate net salvage, it must provide a detailed analysis justifying the reasonableness of applying that method on a forward going basis. For example, inflation rates that are implicit in the proposed cost of removal rates justified. Also, if TURN wishes to reintroduce its net present value recommendation, it should make a full and more detailed showing on how it would be implemented and calculated for all the different classes of plant and what the long term difference is when compared to the methods used by DRA and SCE. Detailed cost of removal showings in the next GRC, which address our concerns expressed in today's decision, will provide the principal guidance as to whether future net salvage should be increased, be decreased, or remain the same.

Regarding PG&E's proposal to limit technical adjustments, we do not feel it is appropriate or necessary to institute a generic proceeding every time a party, other than a utility, proposes technical adjustments to existing methodologies. Generic statewide proceedings should be reserved for broader topics that would present all policy and technical proposals for consideration. In situations where technical adjustment proposals are the same as those proposed in prior proceedings, Commission precedent can be used as reason to accept or reject such proposals, unless new and relevant information indicates otherwise.

17. Differences in Rate Base Forecasts

Following are discussions of the issues related to capital addition forecasts and other rate base items, as identified in the Joint Comparison Exhibit. Unless otherwise indicated capital expenditures and rate base balances discussed are in nominal dollars. The adopted forecasts are incorporated in the development of the adopted plant in service and rate base, both of which are detailed in Appendix C.

18. Rate Base – Plant in Service

18.1. Recorded 2004 Plant Service

In its application showing, SCE uses the 2003 recorded plant balances as the starting point for determining the test year plant balances. SCE forecasts 2004, 2005 and 2006 plant additions in determining the test year 2006 beginning of year, end of year and weighted average plant balances. DRA recommends that the 2004 forecast of plant in service and accumulated depreciation and accumulated deferred taxes be updated for 2004 recorded data, thus providing a more recent starting point. SCE contends that plant should not be updated for 2004 recorded information, because the PTYR mechanism adopted by the Commission in D.04-07-022 gives SCE the opportunity to implement its authorized capital spending budget over a two year period (2004-2005). DRA's proposal to update for recorded 2004 capital additions along with its recommended 2005 capital additions would result in capital additions that are less than SCE's currently authorized capital additions for the post-test years 2004 and 2005. SCE states its expectation that by year end 2005, it will have fully implemented the two year (2004-2005) capital budget approved by the Commission in D.04-07-022.

18.2 Discussion

In past GRCs, updating for more recent recorded information, especially for plant related items, was common. It was not unusual that the utility's forecast for the first estimated year (in this case 2004) would be different than that forecast in the application showing. There might be substantial differences between recorded and forecasted amounts despite the fact that the application was generally filed at the end of the year in question (in this case, SCE filed in December, 2004). The Commission has used updated recorded information in prior GRCs. For instance in A.90-12-018, DRA recommended a $162,649,000 plant reduction based on the use of recorded 1990 plant additions. SCE opposed the adjustment arguing, in part, that decreases in recorded plant may be offset by increases in forecast plant, as plant additions are deferred from the end of the recorded period (fourth quarter of 1990) to the forecast period (1991 and 1992). In D.91-12-076, we stated:

> "We agree with DRA on this point. Although recorded and forecast plant additions do interact, as Edison claims, Edison's analysis ignores the likelihood that deferral of plant at the beginning of a forecast period will be offset by the deferral of plant additions at the end of 1992. Deferral of plant additions is not symmetric. It is more likely that forecast plant additions will be completed late than early. This is typical of construction projects, and may even be influenced by the perverse utility incentive to delay actual construction of new plant once it is put into rate base. We will adopt DRA's $162.649 million reduction."[85]

[85] 42 CPUC 2d at 693-694.

In this proceeding the difference between SCE's forecast for 2004 and the recorded amount is $118,045,000. However, compared to the conditions in A.90-12-018, the issue now is complicated by the PTYR mechanism adopted by D.04-07-022. By that mechanism, SCE was authorized plant additions for 2004 and 2005 based on its proposed budgets for those years, as presented in its 2003 GRC. Ratepayers are protected if SCE spends more than authorized for the 2004 - 2005 period in that rate recovery is limited to the authorized level. Ratepayers are also protected if SCE spends less than authorized, since the revenue requirement associated with any 2004 – 2005 forecasted additions that are not booked during that time period is subject to refund.[86] Because of this, it is not appropriate or fair to incorporate 2004 end-of year recorded plant balance without somehow adjusting 2005 additions to consider that, under the PTYR mechanism, 2004 and 2005 plant additions are viewed as whole rather than separately. It is only because of the previously adopted PTYR mechanism that we will not adopt DRA's recorded 2004 plant balance adjustment in this proceeding.

However, for this GRC, it would be reasonable to consider the results of SCE's 2006 CAAM filing as it relates to both 2004 and 2005 recorded plant

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[86] Pursuant to D.04-07-022, SCE filed advice letter 1808-E that established the Capital Additions Adjustment Mechanism (CAAM) for 2004-2005 to track the difference between actual (recorded) and authorized total company 2004-2005 gross capital additions plus cost of removal amounts. The advice letter notes that if, by the end of 2005, SCE fully implemented its 2004-2005 capital spending budget that was adopted in D.04-07-022 no customer refunds will be required. However, if SCE's authorized capital additions are greater than its recorded capital additions over the entire two year period, an overcollection in revenue requirement will be recorded in the CAAM and this amount will be returned to customers. The Commission approved SCE's Advice Letter 1808-E in Resolution E-3895.

additions. Besides providing consistent treatment of recorded information used for the 2003 GRC, this would provide an opportunity to project the test year 2006 plant balances using the most recent recorded information, even more so than in previous GRCs.

For the 2004/2005 timeframe SCE was authorized gross plant additions amounting to $1,307,000,000 in 2004 and $1,143,000,000 in 2005.[87] The PTYR total authorized plant additions for the two year period is therefore $2,450,000,000.

In this GRC, SCE forecasted gross plant additions of $1,262,000,000 for 2004 and $1,308,000,000 for 2005. The forecasted plant addition total for the two-year period is therefore $2,570,000,000, which is slightly higher than that previously authorized.

A final determination of the need to true up 2004/2005 plant additions through the CAAM will occur subsequent to this decision. In the meantime, for forecasting test year 2006 plant balances for this GRC, we will use SCE's forecasted plant balances through the end of year 2005. We will also establish a memorandum account to track the revenue requirement associated with recorded and SCE's forecasted 2004/2005 plant additions. When plant additions are evaluated for the CAAM, there are two potential outcomes.

The first potential outcome is that SCE records plant additions equal or exceed $2,570,000,000 for the period 2004 – 2005. In that case, no further action is necessary.

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[87] *See* D.04-07-022, *mimeo,* page 275.

The second potential outcome is that SCE records plant additions that are lower than $2,570,000,000 for the period 2004 – 2005. In that case, SCE should credit ratepayers with the excess revenue requirement collected through this decision, that is the difference between the revenue requirement associated with the 2004/2005 plant additions forecasted in this GRC and the revenue requirement associated with the recorded 2004/2005 plant additions. The refund would be calculated from the effective date of this decision.

Although complicated, this process is necessary to avoid results in this GRC that would otherwise be inconsistent with the results of the 2003 GRC. It is difficult to rationalize potentially truing up 2004 and 2005 plant additions for recorded information in the CAAM and then ignoring that recorded information going forward through this GRC cycle. This process will not be necessary in considering plant additions for SCE's next GRC, since the PTYR ratemaking adopted for in this proceeding does not require the use of a CAAM.

Because of our use of the CAAM to determine the 2005 end-of-year plant balance for this GRC, issues related to 2004 and 2005 plant additions are moot. For this reason, as well as our resolution of the post-test year ratemaking for 2007 and 2008 as discussed later in decision, we will only address plant addition issues that relate to the 2006 test year.

18.3 Plant Weighting Percentage

DRA proposes the adoption of the weighting percentage of 41.16% resulting from SCE's plant in service forecast for this GRC. DRA explains that this percentage is consistent with historical weighting percentages. SCE states that the weighting percentage is an informative ratio, indicating the amount of time the total annual additions are included in rate base. SCE argues that its

forecast as to when projects are booked to plant should be found reasonable, not the resultant weighting percentage.

This issue was addressed in SCE's last GRC. In D.04-07-022, we stated:

> "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."[88]

As discussed above, it is not uncommon for a utility to incorrectly estimate plant additions for the first of the forecast years, even though the estimates are made during the year in question. There is no evidence that any utility's ability to accurately forecast the timing of projects gets any better as the length of time related to the estimate increases (test year 2006 plant addition and timing estimates were prepared in 2004). Therefore, in general, we agree with DRA's proposition that a weighting percentage based on historical information is more reliable than that embedded in the utility's budget. However, in this case, the timing of projects as reflected in SCE's 2006 budget and a historical analysis

of the weighting factors are apparently very close and DRA is recommending the use of the 41.16% weighting factor embedded in SCE's budget. This is also very close to the 42.554% weighting factor adopted for SCE in its last GRC.[89] For this GRC, we will therefore use the embedded timing of projects as reflected in SCE's budget for the adopted projects to be included in rates in 2006.[90]

18.4 Allowance for Funds Used During Construction

For purposes of forecasting capital additions in 2005 through 2008, SCE assumed there would be no short-term debt available for construction activities when making its 2005 through 2008 forecast of AFUDC rates. SCE indicates that not all of its short-term debt is available to finance construction activities. The majority is used to finance balancing account under-collections and fuel inventory. SCE states it would not oppose using a three-year historic average of short-term debt available for construction activities for computing the AFUDC rate instead of the value of zero. That amount would be approximately $17,000,000 per year.

DRA recommends that the average short-term debt as a percentage of total capitalization, or 2.61%, be used to determine the short-term debt to be included in forecasting the AFUDC rate for this GRC cycle. SCE estimates that DRA's recommendation would include up to $300,000,000 of short-term debt in the AFUDC calculation, depending on the year.

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[88] D.04-07-022, *mimeo.,* p. 236.

[89] *See* D.04-07-022, *mimeo.,* p. 236.

[90] This also simplifies calculations related to the results of operations program.

18.5 Discussion

The full amount of short-term debt cannot be used to finance construction activities, if there were other obligations for those funds. SCE's explanation that it only has a minimal amount of short-term debt available for construction activities is convincing considering the large amounts necessary to cover balancing account under-collections and fuel inventory. Since, as discussed elsewhere in this decision, we decline to change the financing of fuel inventory from short term debt to the rate of return on rate base, we will assume an amount of short term debt for construction is available during this GRC cycle based on historic information. SCE indicates a three-year average of 2002 ($4,600,000, 2003 ($1,600,000), and 2004 ($43,400,000) would be acceptable. However, the more recent 2004 data better reflects SCE's return to financial health following the 2000/2001 energy crisis. We will therefore include $43,400,000 of short term debt in the calculation of the AFUDC rate for this proceeding.

18.6 Allowance for Costs Transferred from CAC to CIAC

TURN recommends that SCE include, as a reduction to the plant in service forecast, allowances for costs transferred from CAC to CIAC. While SCE reflects the transfer, on a recorded basis, through 2003, it does not reflect the transfer on a forecast basis. TURN's adjustment would reduce the 2006 weighted average plant in service by $2,619,000.

SCE states that it did not explicitly include the estimates for costs transferred from CAC to CIAC in its forecast of plant in service, but argues that it is an insignificant factor that adds no value to the Results of Operations forecast and appropriately was not included. SCE notes that just as there are insignificant factors that would result in a decrease to the plant in service forecast, there are

factors that would result in an increase to the forecast. SCE states that there are numerous parameters that affect actual recorded capital additions, and given the complexity of forecasting the results of operation it is unreasonable to factor every minor parameter into a forecast.

18.7 Discussion

SCE prepared its plant related forecast based on factors it felt were important and determined which plant related items were significant and which were not. Those determinations were reflected in the development of the Results of Operations model. It is reasonable for other parties to question such assumptions and determinations when they are used as bases for ratemaking purposes. We will include the adjustment as proposed by TURN. The adjustment is small but not insignificant when compared to some of the other issues discussed in this decision. Also, SCE indicates that there are a number of such minor adjustments that are not factored into its forecast or the Results of Operations model. If it is not already a part of its filings, SCE's future GRC filings should include a listing and description of all such adjustments to support the reasonableness of its actions.

18.8 SONGS Used Fuel Storage and Marine Mitigation Expenditures

In SCE's last GRC, the Commission adopted a 50-50 sharing between ratepayers and shareholders for costs associated with Spent Fuel Storage and Coastal Mitigation. The Commission stated that because it was 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 impossible to calculate the precise amount of that contribution, the fairest outcome was to

assign equal cost responsibility for the remaining costs of the projects.[91] It was impossible to calculate the ratepayer contribution, because between April 1996 and December 31, 2003, SCE recovered SONGS 2&3 operating costs through a fixed "cents per kilowatt hour" price mechanism identified as Increment Cost Incentive pricing (ICIP). ICIP prices were not tied directly to SCE's cost forecasts during that timeframe.

In this case, SCE has reflected the previous adjustment to only assign 50% of the cost to ratepayers through 2005 but did not reflect that sharing for 2006 or beyond. TURN recommends that the 50% sharing of costs between ratepayers and shareholders continue. However, because SCE's actual spending was somewhat less than its 2003 GRC forecast in 2004 and 2005, TURN proposes a reduction of $9,200,000 in test year 2006 to return to the 50% level previously adopted by the Commission and further reductions of $16,800,000 in 2007, and $6,900,000 in 2008. TURN recommends that these should be permanent disallowances, although in its next GRC, SCE should be able to true up the actual disallowance to actual spending in the historical years.

SCE states that the SONGS 2&3 ICIP mechanism did not include any specific list of capital projects to be completed during the ICIP period, and TURN's proposed additional disallowances of Marine Mitigation and Used Fuel Storage project costs are not warranted.

18.9 Discussion

In D.04-07-022, the Commission found that ratepayers had already paid at least some of the costs of these projects and, because the ratepayer contribution could not be determined, there should be equal cost responsibility

[91] *See* D04-07-022, Finding of Fact 14.

for remainder of the project costs. We are not persuaded to reject our previous finding that ratepayers have already made contributions to the SONGS Used Fuel Storage and Marine Mitigation projects through the ICIP rates. The only reason to deviate from the sharing previously established would be if the ratepayer contribution could be determined and directly reflected. In that vein, specifically in the event that the Commission chose to adopt a continuing disallowance, SCE developed a proxy for determining the maximum that ratepayers could have contributed during the ICIP period and the maximum adjustment that should be imposed. SCE attempted to tie the assumptions in the test year 1995 GRC to what was in rates during the ICIP period and compare that to what was recorded. SCE asserts that the difference would be the maximum adjustment that should be made.

There is merit to SCE's proxy approach. While not definitive,[92] it provides a more objective basis for assigning costs that were paid by ratepayers during the ICIP period. We will adopt it for this GRC cycle and reduce the 2006 beginning-of-year SONGS plant balance by $22,600,000[93] (100% share). SCE's share of the adjustment is $16,951.000.

18.10 Mohave Capital Additions

As discussed previously in the section dealing with Mohave O&M costs, we stated our preference to assume a temporary shutdown scenario as recommended by DRA and to reflect SCE's forecasted O&M and capital

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[92] For the used fuel project, it is not certain that the amount of money identified for the 1995 -1997 timeframe was the total cost of the project or just the amount that would be spent through 1997. This may be relevant because the ICIP period lasted through 2003.

[93] *See* Exhibit 89, pp. 35 -38 and Exhibit 91, Appendix G for the development of the adjustment.

additions associated with that scenario in the test year. SCE's adopted share of Mohave capital additions is therefore $2,517,000 for 2005 and $2,821,000 for 2006. As discussed previously, the related capital costs will be used to establish the temporary rate recovery of Mohave costs. Recorded costs associated with the temporary shutdown scenario will be entered into a two-way balancing account; and permanent recovery will be determined in a future reasonableness review.

18.11 Florence Dam Repairs

SCE's forecasted test year rate base includes $1,545,000 for buttress repairs at Florence Dam. In SCE's last GRC, these repairs were included in D.04-07-022 as O&M costs, amounting to $800,000, that were expected to occur during 2003. According to SCE, when it implemented the Florence Dam Buttress repairs, the scope of work changed from that forecasted and the costs almost doubled to $1,545,000. This change, caused SCE to conduct another review of this project, to assure the proper accounting was being used. Commensurate with its capitalization policies and accounting guidelines, SCE determined that the Florence Dam Buttress repair project costs should be capitalized. The project was completed in 2003 and is included in the recorded plant balances used in this GRC as the base for projecting test year plant balances.

TURN recommends that the $1,545,000 of Florence Dam Buttress Repair costs not be recovered in rate base but that these costs instead should be deemed to be an O&M expense. TURN maintains that the costs of this project were already recovered from ratepayers in the test years and attrition years through the adopted 2003 O&M expense, and it would be unreasonable to recover those costs a second time through the capitalization of the same costs, as proposed by SCE in this rate case. TURN states that its recommendation is not retroactively adjusting 2003 results but is the result of a reasonableness review in

this case of a capital expenditure that was specifically not requested or authorized in the last rate case.

SCE argues that the Commission should not retroactively modify the capitalization of these costs. SCE indicates that Hydro overspent its 2003 authorized O&M by $800,000 and overspent 2003 authorized capital (on a direct expenditure basis) by $3,100,000. Since it spent more for hydro maintenance expenses than what was authorized in 2003 rates, SCE asserts that there is no possibility of double recovery of the Florence Dam Buttress repair project.

SCE also cites D.04-07-022, Finding of Fact 8, which states:

> 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 . . . SCE requires flexibility to optimally respond to changing circumstances.

18.12 Discussion

Normally, we take a fairly broad view when looking at what was included in rates and what was actually spent. The general concept of test year ratemaking is to authorize a rate level based on a reasonable forecast of various revenues and costs. Once rates are set, the utility has the discretion and responsibility to spend its funds in the most cost effective manner to proved safe and reliable service. However, in D.92-12-019, the Commission stated:

> 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. (D.92-12-019, 46 CPUC 2d 538, 555.)

SCE has provided information to show that, for hydro O&M expenses and capital expenditures, it spent more than what was adopted for test year 2003. However, inclusion of the Florence Dam project was the basis for setting rates for 2003, 2004, and 2005. If that project, which was specifically identified and justified by SCE and included in the adopted test year 2003 O&M forecast, were excluded from that adopted forecast, SCE would have received approximately $2,000,000 less than they actually received over the test year 2003 GRC cycle. SCE has not provided any information on its recorded hydro spending in 2004 or 2005.

We must also consider the ratemaking implications of changing the projected O&M expense to a recorded plant addition. There is an advantage to SCE in making this change, since in 2003 it overspent its hydro O&M budget. The costs of the Florence Dam project would not have been fully covered by rates in that year. By switching to capital, most of the costs will eventually be recovered, since the non-depreciated balance would be covered in rates going forward. SCE explained the decision to capitalize, in a data request response to TURN. SCE stated:

> …As stated in the email, Remark #3 of the subject CPR catalog account had been clarified to read surfacing instead of facing in August 2003, as a result of inquiries made by Northern Hydro employees regarding this project earlier in 2003. Prior to that clarification, the remark had been interpreted to apply only to the upstream face of the dam. This special remark was added back in 1992 instead of creating a new retirement unit. Although the special remark originally referred to the "facing" of the dam, the reference meant the entire

> surface. Based on these criteria, added in 1992, the Florence Dam buttress surfacing qualified as capital.[94]

It appears that this project should never have been included in the expense forecast for the test year 2003 GRC. The data request response does not indicate that the scope of the project changed.[95] In fact, the response indicates the original reference meant the entire surface. It was a mistakenly included as an anticipated maintenance expense because it was described or interpreted as "facing" rather than "surfacing." If the project had been classified correctly all along, there would be no dispute now. It would have been included correctly as a plant addition in 2003.

SCE should not benefit, just because it made a mistake in originally classifying this project as expense. For this GRC cycle, we will exclude the Florence Dam buttress repair as recommended by TURN. The beginning of year 2006 plant balance should be reduced by $1,545,000. Before the costs are included in any future rate case, SCE must provide convincing evidence that it did not benefit unduly by switching the project from expense to capital and sufficiently address the Commission's concerns expressed in D.92-12-019, as indicated above.

18.13 Transmission & Distribution Meter Set Costs

SCE's expenditure forecast for meters is based on the number of new customer meter sets time the cost per meter (CPM) set with cost escalation. DRA

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[94] Exhibit 357, Appendix 10.

[95] The difference in the estimated expense and the recorded plant addition amount is not explained or detailed. For instance, there may be overheads in the capital addition that would be reflected otherwise as an expense (*e.g.*, pensions and benefits).

proposes the recorded cost experience by SCE in 2004 be held constant for 2005 and 2006 at $2,922 per meter. Multiplying this cost per meter by SCE's estimates for additional meters results in an DRA adjustment of $7,170,000 for test year 2006.

SCE states that there is no evidence that productivity or cost reductions will offset cost escalation associated with these activities. SCE calculates that adding the T&D capital escalation to the recorded 2004 CPM of $2,922 would yield a $3,010 CPM for 2005 and $3,100 for 2006, both of which are higher than its forecasts and concludes that DRA's analysis, when adjusted for inflation, actually corroborates the reasonableness of SCE's forecast CPM.

18.14 Discussion

We note that TURN proposed an adjustment to this plant category, but after SCE fixed a discrepancy in the 2004 and 2005 CPM that affected the test year CPM, TURN no longer opposes SCE's forecasts. We will therefore only address the SCE and DRA difference. Regarding its position to hold the 2004 recorded unit costs constant, DRA asserts it is reasonable to expect that overtime labor, contract labor, and contract overtime labor costs will stabilize at current levels. While there is no specific evidence which quantifies productivity or other cost reductions that would offset cost escalation, DRA points out that due to the increased number of linemen from 2003 (647 linemen) to 2006 (828 linemen), overtime embedded in the 2004 recorded CPM would be reduced and would offset cost escalation associated with the other CPM activities. That 77,437 actual 2004 meter sets exceeded the forecast of 73,749 meter sets implies additional overtime would have been necessary to some degree. To the extent that overtime may be reduced due to the 28% increase in linemen from 2003 to 2006, it is reasonable to assume some cost savings to at least partially offset cost

escalation.[96] Since this is a labor intensive activity cost reductions resulting from reduced overtime may be substantial. We are persuaded by DRA's argument to hold the CPM at $2,922 for 2006 and will incorporate it in determining the test year estimate of $210,124,000 for this capital activity.

18.15 Line Extensions

Regarding line extension allowances for existing customers, TURN recommends that line extension allowances for new panel upgrades should not be granted because they are not justified. Also, no line extension allowances should be granted for home remodels that do not entail an electric panel upgrade or for conversions to underground service. The necessary data was not available for TURN to adjust SCE's capital budget to exclude ratepayer funding for providing new services to existing customers. Therefore, TURN recommended the following:

First, the Commission should change the language contained in Section F.1.a.of Rule 16 concerning service reinforcements to the following:

> SCE Owned. When SCE determines that its existing Service Facilities require replacement, the existing Service Facilities shall be replaced and the Applicant shall pay Edison its total estimated cost of replacement.

Second, if the Commission believes this unduly harms applicants that must have their services replaced for a panel upgrade or service reinforcement, it could treat these panel upgrades as a nonresidential service extension and require Edison to calculate the actual incremental revenues associated with a panel upgrade on a customer specific basis. Instead of receiving the full

[96] These potential cost savings are separate from the productivity associated with pilot programs related to SCE's Business Process Integration.

residential line extension allowance that is based on total average annual residential distribution revenues, this alternative would only credit applicants for their incremental distribution revenue.

In its direct testimony, TURN also raised several objections to the treatment of line extension allowances including the calculation of line extension allowances in general, the exclusion of sub-transmission costs in the calculation of line extension allowances, and the utilities' data collection practices regarding line extension costs and projects. However, in its opening brief, TURN suggests that, in light of Resolution E-3921,[97] these issues should be removed from this rate case and the Commission should order SCE to revise its calculation of line extension allowances according to the modifications adopted in Resolution E-3921.

SCE notes that TURN's opening brief states: "While Edison's interpretation of its service reinforcements under Rule 16 may be technically valid, it eviscerates the spirit of the Commission's long standing policies to revenue justify new customer connections." SCE argues that TURN thus

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[97] In response to DRA and TURN protests to SCE Advice Letter 1847-E seeking approval to increase its current line extension allowance, Resolution E-3921, issued on June 16, 2005, reduced SCE's proposed distribution rate by its baseline credit (0.625 cents/kWh) and imposed a COS factor of 17.52% per year versus SCE's proposed COS factor of 16.20% per year. The resolution also directed the utilities to file applications within 90 days that address possible changes in policy and the methodology for determining line extension allowances. Among other issues, the applications will address alternative methods of calculating the net revenue on which future line extension allowances are based, revenues sources to be used when calculating the allowance (including that from substations, primary circuits, and sub-transmission), sources of data for calculating the allowances, and the criteria for requiring that a revenue impact estimates be included in an allowance change advice letter filing.

acknowledges that SCE is complying with the language of that tariff rule, and what TURN seeks is a change to that tariff. SCE states this is not appropriate in this proceeding for three reasons:

> First, such a change would affect not only SCE, but the other California utilities that have similar tariff rules.
>
> Second, the Commission's line and service extension proceeding already provides a forum to review residential line extension allowances.
>
> Third, TURN itself has stated that issues surrounding line and service extension allowances "should be removed from this rate case." Since line and service extension allowances are intertwined with the operating language of SCE's Rule 15 and Rule 16 tariffs, TURN should raise this issue in that other proceeding, where it properly belongs.

18.16 Discussion

Regarding line extension allowances for existing customers, SCE is in compliance with its current tariff language. We agree with SCE's position that the changes to Rule 16 may well affect other utilities and a generic proceeding would be the appropriate forum to make such changes. TURN's concerns regarding line extension allowances for existing customers should be brought up in SCE's A.05-10-019, which addresses residential line and service extension allowances. It is likely this application will be addressed concurrently with similar applications by SDG&E and PG&E.

18.17 Leased Meters

TURN recommends that the Commission exclude costs of leased meters from plant-in-service and rate base in the amount of $1,000,000 in 2006, $1,300,000 in 2007, and $1,500,000 in 2008. According to TURN, leased meters should either be paid for through special facilities agreements or should be paid up front by the customer as CIAC.

In response, SCE states that meter leasing other operating revenue (OOR) is recorded and forecast in several OOR accounts. According to SCE most of the associated OOR that customers pay for these leased meters is recorded and forecast in TDBU accounts 454.300, 454.350, 456.700, and 456.900 when metering is installed on Added Facilities and Interconnection Facilities. Revenues from meters leased under Rule 2J are forecast and recorded in OOR account 454.100, managed by CSBU. Also, SCE forecast OOR for accounts 454.300, 454.350 and 456.700 based on the forecasted plant balances and the applicable Commission approved added facilities rate. A five-year average was used to forecast OOR for account 456.900. Based on these facts, we find that SCE's OOR forecast reasonably reflects revenues associated with forecasted costs of leased meters and will not adopt TURN's recommendation to exclude such costs from rate base.

18.18 Load Growth Projects

SCE proposes a number of load growth projects (primarily in the form of new or expanded substations) to meet projected growth for customer load throughout its service territory. Also included in this category are capital expenditures necessary to interconnect new generating plants to the system. For this activity, SCE forecasts plant additions of $73,240,000 for 2005 and $84,532,000 for 2006. DRA forecasts plant additions of $56,571 for 2005 and 76,327,000 for 2006. DRA recommends postponing two projects indefinitely and deferring seven projects for one year. Because of the proposed deferrals, DRA also reduces the distribution substation program because the purchase of certain distribution circuits can likewise be deferred for one year.

18.19 Discussion

Four of the projects[98] in question are budgeted to go into service in 2005. As discussed earlier in this decision, we will be truing up estimates for 2005 to conform to the amounts authorized in D.04-07-022 through SCE's compliance with the CAAM. In the meantime, we are including SCE's estimates for 2005 in our decision today. For this reason, we will adopt SCE's request for these four load growth projects subject to adjustment for 2005 through the CAAM. We note SCE's admission that two of the projects – San Bernardino and Arrowhead may be of lesser priority than other projects required to avoid significant overloads. However, if these projects are ultimately completed in 2005, they should be recognized in rates as SCE has provided sufficient information concerning the prudence of the projects.

For the remaining projects DRA is recommending a deferral of one year, from 2006 to 2007. DRA concludes that there is a low probability of exceeding the utilization factors identified by SCE, provides an alternative approach to calculating projected loads, and assumes an overload capability above 100 % utilization. While there may be merit to DRA's analysis, it is clear that the projects need to be done in the near future. Whether or not certain events will coincide such that 100% utilization will occur or whether and by how much name plate ratings can be exceeded are secondary to the fact that the projects are needed and are needed soon.

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[98] San Bernardino ($1,720,000), Arrowhead ($1,510,000), Rush ($740,000), and Kernville ($820,000) Substations.

In summary, we adopt SCE's request regarding the load growth projects, with the understanding that certain costs may need to adjusted as a result of SCE's upcoming CAAM analysis/filing.

18.20 Distribution Capital Replacement Program

SCE forecasts a total of $907,700,000 (2004 – 2008) for its Distribution Capital Replacement Program in order to address an increasing volume of infrastructure components wearing out and needing to be replaced. SCE indicates:

- The increased volume of pole replacements and repairs reflect increased levels of inspection performed in order to meet the requirements of GO 165 and that performing fewer than forecast pole replacements and repairs will put it in non-compliance with regulatory requirements.
- An increase in the volume of preemptive replacements of underground switches and cable is necessary to deal with the increasing number of circuit interruptions due to failures of underground equipment, as well as to enhance public and employee safety.
- Old and obsolete automatic reclosures need to be replaced at a rate slightly less than achieved in 2000 and 2002 in order to manage system reliability and to enhance public safety.
- Capacitor banks need to be replaced at a rate slightly less than achieved in 2003 in order to provide adequate voltage to customers and ensure grid reliability.
- A modest number of underground vaults and manholes are forecast for replacement, because these are showing signs of weakening and potential collapse.

- Refurbishment of the worst performing circuits is necessary to move all customers toward the same level of service.

In general, SCE has provided information that supports a need to replace certain portions of its distribution infrastructure at rates in excess of recorded rates. We will evaluate SCE's requests for the various aspects of its proposed infrastructure replacement program with that in mind. However, SCE still has the burden to justify the need and costs of each of its various proposed elements of the program.

Discussions relate to test year 2006 costs only. As discussed earlier in this decision, we will be incorporating 2005 recorded information into this proceeding via SCE's CAAM filing in 2006. In the meantime, we will include SCE's forecast of capital expenditures for 2005.

As discussed below, we have evaluated SCE's test year 2006 proposals and considered DRA's recommendations in developing the test year forecasts. For the amounts at issue, SCE requests $253,900,000 for 2006, while DRA recommends an amount of $80,500,000. We adopt a test year 2006 forecast of $188,814,000.

18.20.1. Wood Pole Replacement Program

SCE states that the increased volume of pole replacements reflect increased levels of inspection performed in order to meet the requirements of GO 165. Most of the pole replacements for 2005 and 2006 have already been identified and scheduled. Performing fewer than the forecast number of pole replacements will put SCE in noncompliance with regulatory requirements. SCE forecasts 14,900 pole replacements in 2005 with an expenditure of $116,000,000 and 14,800 pole replacements in 2006 with an expenditure of $119,300,000.

DRA recommends 9,512 pole replacements in 2005 with an expenditure of $74,500,000 and 6,499 pole replacements in 2006 with an expenditure of $52,4000,000. DRA states that its recommendation is consistent with recent historical pole replacement levels and costs, and includes poles with Priority Codes 1 through 4. It also takes into consideration a normalized level of intrusive inspections for years 2006 through 2008. It is DRA's position that SCE has not provided any reasons or data to support an increase over the historical replacement level in its Application.

According to DRA, SCE could not identify the number of poles replaced historically as a result of intrusive inspections although its 2005 and 2006 pole replacement forecast is based on the number of 2005 and 2006 intrusive inspections.

DRA argues that SCE was over-ambitious in its forecast for deferred pole replacement based on the number of Priority Code 3 poles scheduled for replacement in 2005 and 2006. According to DRA, since SCE only replaced 65 deferred poles in 2002 and 124 deferred poles in 2003, SCE's forecast of 3,769 deferred poles for 2005 and 2,332 deferred poles for 2006, appears to be excessive.

Regarding the number of poles due for replacement for years 2004 through 2008 that SCE claims necessary as a result of pole inspections required by Commission's GO 165, DRA states that SCE should have been cognizant of the requirements of GO 165 since 1997, and the company should have been replacing affected poles all along, not deferring the replacement work until 2005 and 2006 when the company filed its GRC Application. DRA points out, between 1999 and 2003, the company replaced an average of 7,500 poles each

year and that for 2005 and 2006, SCE is forecasting a replacement level that is almost twice this number: 14,900 for 2005 and 14,800 for 2006.

In response to DRA criticism of SCE's forecast of 3,769 deferred poles for 2005 and 2,332 deferred poles for 2006 as being excessive, SCE states, these pole replacements will not have been deferred but will be performed on time. SCE's rebuttal shows that most pole replacements are Priority Code 4 and will not occur until three years after their inspection. According to SCE, these pole replacements are not discretionary, as DRA suggests, but necessary to comply with procedures written, in turn, to comply with GO 95.

Regarding compliance with GO 165, SCE argues that GO 165 simply establishes a deadline by which all utilities must have completed their inspections. It says nothing about the rate at which these inspections must or should be performed. SCE further states that it has not been "deferring" needed expenditures. It has not been earning its authorized rate of return due in part to expending more capital than authorized. Regarding DRA's claim that SCE's forecast of pole replacements as a result of intrusive inspections excessive and unsupported, SCE states that the data DRA wanted had been archived as they were not relevant to SCE's day to day operations, (*e.g.,* the priority code assigned to a pole which was replaced years ago.)

According to SCE, SCE based its pole replacement forecast on a detailed analysis of historic inspections and their results in terms of rejection rates by priority code. SCE (1) broke down the historical rejection rates by geographical location; and (2) determined how many would be inspected in that specific location from 2005 through 2006. SCE argues that this level of detail represents the most reasonable forecast possible.

18.20.2. Discussion

As discussed earlier in this decision, we will be incorporating 2005 recorded information into this proceeding via SCE's CAAM filing in 2006. In the meantime, we will include SCE's forecast of pole replacements and costs for 2005. Regarding estimates of pole replacements for 2006, DRA has proposed an alternate forecasting methodology that is consistent with historical levels of pole replacements and costs. However, DRA has not explained, under its proposal, if or how SCE can meet pole replacement requirements identified as a result of GO 165 inspections. SCE has provided information on the number of poles identified for replacement by priority, both as a result of past inspections and forecasted replacements based on future inspections. Considering the GO 165 requirement that all wood poles over 15 years, which have not been subject to intrusive inspection must be intrusively inspected within ten years,[99] SCE's estimates appear generally reasonable. For ratemaking purposes, rather than assuming replacement of 14,800 poles for 2006, 11,134 poles for 2007 and 11,160 poles for 2008, we will use the average of 12,365 poles for each of the years. Use of SCE's proposed unit cost of $8,060 for 2006 results in our adopted test year 2006 estimate of $99,659,000 for the wood pole replacement program, as opposed to SCE's estimate of $119,300,000.

18.20.3. Underground Distribution Switches

SCE is requesting $12,000,000 in 2005 and $28,000,000 in 2006 for the preemptive replacement of underground distribution switches and fuse

[99] Ten years from the issuance of GO 165 will be March 2007.

cabinets. Switches are used for opening or closing electrical circuit connections. SCE states that its "planned annual replacements rely heavily on judgment."[100]

DRA states that since the 1990s, SCE has been aware of problems with Buried Underground Residential Distribution (BURD) switches and mainline switches and has been replacing them preemptively over the past few years. Between 2000 and 2004, with the exception of 2001 when zero switches were replaced, SCE has been replacing switches at an average rate of 69 switches per year under this program. DRA concludes that SCE has not provided any justification to deviate from past replacement levels.

Based on a lack of data available to support an increase in the replacement rate over historical levels, and the fact that switch failures have been an on-going issue, DRA recommends continuing the level of replacement that SCE has been performing most recently. SCE's 2004 recorded data shows a total of 90 switches with an expenditure of $4,000,000. There has been no replacement of fuse cabinets from 1999-2004. Based on this recent data, DRA recommends a total of 90 switches for 2005 and 2006 with an annual expenditure of $4,100,000 and $4,200,000, respectively.

18.20.4 Discussion

SCE estimates a total of $27,580,000 for the replacement of underground distribution switches. SCE plans to replace 143 mainline manual oil-filled switches in 2004 and 200 in 2005. Of the remaining 1857, SCE plans to replace 300 in 2006. At a replacement rate of 300 per year, SCE would replace the remaining manual switches over six years, which for the purposes of this GRC

[100] SCE, Exhibit 42, p. 37.

appears reasonable. Therefore, we will adopt SCE's estimate of 300 manual oil-filled switch replacements for 2006.

SCE has identified 131 mainline spring operated oil-filled switches with known problems and intends to replace 15 per year from 2005 to 2008. This appears reasonable and will be reflected in rates.

There are 6,343 spring operated oil-filled switches with no defects. SCE plans to replace 10 in 2005 and 85 in 2006. SCE has not provided a compelling reason to increase the number of replacements from 10 to 85, and we will use 10 replacements for 2006.

SCE states there are 1,100 oil filled BURD switches older than 30 years old that pose the same reliability and safety issues as posed by the mainline oil switches. SCE plans to replace 125 in 2005. The immediate need to replace 900 switches over the 2006 – 2008 time period is not evident. For this GRC, we will provide a moderate increase over the amount planned for 2005, by assuming the remaining 975 switches are replaced over a six-year period at 162 per year.

Out of 957 submersible fuse cabinets SCE plans to replace 20 in 2005 and 250 in 2006. SCE indicates that while external inspections are performed every three-year, no internal inspections are made because opening the cabinets' risks destruction of the water-tight seal and the cabinets are extremely old. SCE states that while not a safety issue, the proximity of many submersible fuse cabinets to their expected end of life will impact reliability. Almost 400 submersible fuse switches are older than 40 years old. It appears the replacement of all of the cabinets is a reasonable course of action. However SCE does not support the immediate need to replace 750 of the remaining 937 over the 2006 – 2008 timeframe. For this GRC, we will instead assume 125 cabinet

replacements per year. While less than requested by SCE, it is still a substantial increase from the total of 20 planned for the 2004 – 2005 time period and provides funds to replace the switches that are older than 40 years.

Based on SCE's estimates of the unit costs of the switches, the adjustments described above, we calculate expenditures for 2006 to be $19,537,000. This reduces SCE's test year request for underground distribution switches by $8,043,000.

18.20.5. Underground Primary Cable

SCE states a need to increase its preemptive replacement of underground cable in order to avoid a significant decline in system reliability. SCE states that the number of circuit interruptions due to cable failure is increasing, and modest volumes of replacements are proposed (0.1% of the cable system in 2005 and 0.5% in 2006). Specific sections to be replaced will be determined by a combination of age, circuit performance, and judgment.

DRA believes SCE's forecast is excessively high and unreasonable. According to DRA, SCE only provided information which rates replacement factors for paper insulated lead covered (PILC) and cross-linked polyethylene (XLPR) cables, and has not supported its request for replacing high molecular weight polyethylene (HMW-PE) cable.

SCE has forecasted underground cable replacement costs to be $10,200,000 in 2005 and $35,000,000 in 2006. DRA recommends costs of $459,000 in 2005 and $0 in 2006.

18.20.6. Discussion

SCE proposes a five year plan to replace 860 miles of PILC and HMW-PE cable (14% of current inventory). From 1999 to 2003, SCE has replaced 70 conductor-miles of underground cable. They planned 0 miles in 2004, due to

budget constraints, 60 miles in 2005, 200 miles in 2006, 300 miles in 2007 and 300 miles in 2008. SCE also shows that the sustained interruptions due to underground failures ranged from about 200 to 250 sustained interruptions per year from 1994 to 1999. From 2000 to 2003, the range has increased to about 300 to 350 sustained interruptions per year, despite replacement of 70 miles of cable. From this information, it is reasonable to assume that a replacement at a rate greater than in the past is necessary to maintain or reduce the sustained interruption rate.

What is not clear is what the replacement rate should be. SCE states precise engineering data is not available and that its proposed replacement volumes are admittedly heavily based on judgment. SCE argues that to delay replacement of cable pending the availability of precise engineering data will institute a defacto policy of running cable to failure and that the inescapable eventual result of such a policy would be significantly poorer system reliability than what customers experience today. In general, we agree with SCE. However, the proposed 200 to 300 miles of cable replacement per year is a significant increase over the recorded level of 14 miles per year over the 1999 - 2003 timeframe or the planned 60 miles of cable replacement in 2005. Without more engineering data, we would prefer to moderate the increased rate of cable replacement and will instead assume 100 miles per year of cable replacement for this GRC cycle, which is a substantial increase to the 60 miles of cable replacement planned by SCE for 2005. While less than that requested by SCE, it should be sufficient to provide information on the effect of an increased rate of cable replacement on the number of sustained interruptions. Hopefully precise engineering data will also become available for analysis in the next GRC.

This reduces SCE's request for replacement of underground primary cable from $35,000,000 to $17,500,000 for test year 2006.

18.20.7. Automatic Reclosers

SCE states that old and obsolete automatic reclosers (ARs) need to be replaced at a rate slightly less than that achieved in 2000 and 2002 in order to manage system reliability and also to enhance public safety. In order to replace 20 ARs per year, SCE requests funding of $1,130,000 in 2005 and $1,1700,000 in 2006.

DRA states that SCE did not support its forecast and recommends the use of replacement history to forecast the number of replacements. DRA recommends costs of $566,500 for 2005 and $583,500 for 2006, based on 10 replacements per year.

18.20.8. Discussion

DRA's recommendation is based on an average of 2002 to 2004 data. According to SCE, 22 ARs were replaced in 2000 and 21 in 2003. No replacements were possible in 2001 due to the financial crisis, only nine were replaced in 2003 and none in 2004 due to lineman resource limitations and corporate financial restraints due largely to the priority of meeting higher than expected customer demand. The financial crisis was an extraordinary circumstance and its effects should be ignored for forecasting purposes. However, diversion of costs due manpower constraints or higher priorities is not extraordinary and may be reflective of what happens in the test year. While, as discussed previously, we will use SCE's estimate for 2005 subject to the CAAM review in 2006, we will base the 2006 forecasted number of AR replacements on the average of 2000 – 2004 closures, excluding 2001. This results in 13 replacements in 2006 at a cost of $759,000.

18.20.9. Capacitor Banks

SCE maintains that capacitor banks need to be replaced at a rate slightly less than that achieved in 2003 in order to provide adequate voltage to customers and ensure grid stability. SCE requests funding amounting to $6,900,000 in 2005 and $7,100,000 in 2006.

DRA states that it requested detailed historical data regarding failed and obsolete capacitor units by type for the years 1999-2004, which SCE could not provide. Based on the limited data provided, DRA escalated recorded 2004 data to develop its forecasts for 2005 and 2006 in the amounts of $5,900,000 and $6,100,000, respectively.

18.20.10. Discussion

As discussed previously, we will use SCE's estimate for 2005 subject to the CAAM review in 2006. For the test year, DRA recommends funding at the 2004 level. SCE criticizes DRA for providing less funding than what SCE expects to fund going forward. SCE, on the other hand, does not explain why its 2004 recorded amount is low compared to what it suggests it needs for the future years. It is not clear why the increased level of replacements is necessary. In this situation, the use of the most recent information is reasonable and we will adopt DRA's recommended funding level of $6,100,000 for test year 2006.

18.20.11. Underground Structures

SCE forecasts $1,100,000 in 2005 and $8,300,000 in 2006 to replace underground vaults and manholes which are showing signs of weakening and potential collapse. According to SCE, this, as part of the infrastructure replacement program, is a new program that addresses an emerging problem.

Collapse of these concrete structures poses a risk to public safety and system reliability.

Based on its perceived lack of information supporting SCE's request and understanding that damaged equipment should be tracked in a different account, DRA recommends no funding for this program in 2005 and 2006.

18.20.12. Discussion

We recognize SCE's argument that this is a new program and that SCE has not replaced deteriorated vaults and manholes of the type proposed here prior to 2004, the year SCE began to replace pre-cast underground concrete structures as part of its infrastructure replacement program. For 2005 and 2006, it is reasonable to recognize the new program as part of infrastructure replacement.

Based on known problems, SCE has justified replacements planned for 52 vaults/manholes and 74 BURD structures from 2004 through 2008. For 2006, the allocated costs would be $3,520,000. However, SCE indicates its belief that there may be more underground vaults and manholes that are candidate for replacement beyond these amounts. SCE therefore allocated additional funding for analyzing and replacing 22 additional structures in 2006 at a cost of $4,780,000. We find insufficient justification for more than doubling the request for projects that may or may not be undertaken. We therefore include only $3,520,000, for known and needed projects, in the test year estimate.

18.20.13. Annual Circuit Review Program

In 1997, SCE instituted the Annual Circuit Review Program. SCE states that the objective of the program is to maintain the overall reliability of the distribution system despite the tendency toward less reliability due to

infrastructure aging. According to the company, the basic premise of the program is that the most cost-effective way of impacting overall system unreliability is to direct resources toward the larges individual contributors to that unreliability. Consequently, SCE's practice has been to focus on the worst-performing circuits ranked using objective measures of reliability.

SCE proposes to remediate five circuits in 2005, 15 circuits in 2006, 20 circuits in 2007 and 20 circuits in 2008, at a cost of $1,000,000 per circuit. DRA accepts the 2005 proposal to remediate five circuits and extends that number to 2006. DRA also recommends a cost per circuit of $500,000 based on the use of more current information.

18.20.14. Discussion

Regarding the forecast of the number of circuits to be remediated, SCE states that available funds and workforce resource limitations preclude it from doing this work in 2004. Also, they have only planned to remediate five circuits in 2005. While, as suggested by SCE, this program may be a very cost-effective way of staying the effects of infrastructure replacement, it does not appear to be a high priority for funding. For the years 1999 to 2003, excluding 2001 due to the energy crisis, SCE remediated an average of eight complete circuits per year. We will use that annual amount for the forecasted years for this GRC cycle.

SCE states that the cost per remediation can vary widely depending on circuit length, number of customers, age of circuit, and whether the circuit is located in urban or rural areas. In 1999, eight circuits were remediated at an average cost of $1,500,000. In 2002 and 2003, ten circuits were remediated at an average cost of about $500,000. Due to the wide variance in costs and SCE's explanation of the possible reason, it is not clear that use of the

more recent 2002-2003 information, as recommended by DRA, would produce better estimate of future costs than would the 1999 information. SCE's rough estimate of $1,000,000 per remediation appears reasonable.

Use of our adopted forecast of eight remeditated circuits per year at an average cost of $1,000,000 results in a test year 2006 estimate of $8,000,000 for the Annual Circuit Review Program, as opposed to SCE's request of $15,000,000.

18.20.15. Wood Pole Repairs

SCE's forecast of wood pole repairs was based on the number of poles already identified for repair which must be completed to avoid non-compliance with regulatory requirements. SCE forecasts costs of $13,900,000 for 2005 and $19,900,000 for 2006.

DRA is reluctant to rely on historical cost data and number of poles forecast to be intrusively inspected as the bases for its forecast, since it perceives recorded pole and cost data to be unreliable. DRA based its repair expenditure estimates of $1,500,000 for both 2005 and 2006 on recorded 2004 cost data for steel stubbing and fiberglass wrapping.

18.20.16. Discussion

Attached to its rebuttal, SCE provided the structure numbers for all deteriorated wood poles identified to be repaired by fiberglass wrap or steel stub in 2005, 2006 and 2007. SCE states that in order to comply with GO 95:

- By the end of 2005, 743 poles must be fiberglass wrapped and 733 poles must be steel stubbed.
- By the end of 2006, 3,561 additional poles must be fiberglass wrapped and 5,446 additional poles must be steel stubbed.

- By the end of 2007, an additional 4,809 poles must be fiberglass wrapped and an additional 7,926 poles must be steel stubbed.

SCE indicates that it will not be able to perform the nearly 13,000 pole repairs due in 2007. A significant number of repairs must be completed ahead of their compliance due dates. SCE's current plan is to perform 1,745 fiberglass wraps and 2,691 steel stubs in 2005, and 4,000 fiberglass wraps and 6,000 steel stubs in 2006. This will leave roughly the same number (about 3,500 fiberglass wraps and about 5,500 steel stubs) to be performed in 2007. SCE states that its GRC forecast (developed in early 2004) of 27,000 pole repairs in 2005-2007 was only slightly conservative and that its current forecast for repairing the deteriorated wood poles that it knows with certainty must be done, provides it with the best chance of compliance with Commission regulations.

In general, we agree with SCE and will provide the opportunity to repair all identified poles needing repair through 2007. Based on SCE's plan as indicated above, it will need to wrap a total of 7,368 poles in 2006 and 2007 and stub an additional 11,516 during that same time period. In its original showing, SCE also estimated 2,000 wraps and 3,000 steel stubs in 2008. For ratemaking purposes, we will normalize the repairs over the three-year GRC cycle by providing for 3,123 wraps and 4,839 stubs for each of the three years. Use of SCE's 2006 unit costs results in 2006 expenditures of $9,600,000 for wraps and $6,200,000 for stubs, for a test year total of $15,800,000, which we will adopt.

18.20.17. Bark Beetle Pole Replacement

SCE has modified its request for bark beetle pole replacement, since the program will now end in 2005. For 2005, SCE now estimates expenditures of $3,500,000. DRA's estimate of $4,500,000 was developed using

more recent data than was available when SCE wrote its original testimony and estimated 2005 costs of $7,964,000 and 2006 costs of $3,318,000.

18.20.18. Discussion

Costs now will only be incurred in 2005 and, as discussed earlier in this decision, we will be incorporating 2005 recorded information into this proceeding via SCE's CAAM filing in 2006. In the meantime, we will include SCE's forecast of capital expenditures for 2005. We will adopt SCE's latest estimate of no expenditures in 2006.

18.20.19. Sub Transmission Wood Pole Replacement

SCE based its forecast of pole repair/replacements on work already identified and scheduled, compliance driven inspection frequencies and historic rejection rates. SCE expects to replace 986 poles, fiberglass wrap 105 poles and steel stub 201 poles in its subtransmission system in both 2005 and 2006. SCE forecasts expenditures of $19,500,000 for 2005 and $20,100,000 for 2006. SCE's estimated cost per pole replacement is $18,400, in 2004 dollars.

DRA escalated 2004 recorded expenditures to develop its forecast of $12,500,000 for 2005 and $12,900,000 for 2006. Embedded in DRA's forecast is a recorded cost per pole replacement of $14,197 per pole.

18.20.20. Discussion

In general, SCE's forecast of work activity, which is based on repair/replacements on work already identified and scheduled, compliance driven inspection frequencies, and historic rejection rates, is reasonable. However, SCE's recorded pole replacement costs for 2004 were substantially less than projected, principally due to the cost per pole being significantly less than forecasted. SCE explains that a very high percentage of poles replaced in 2004 were located in the San Joaquin region, which has been shown to have a

relatively lower replacement cost due to its rural nature and ease of work. While the explanation seems reasonable, SCE does not explain if or how its forecasted price per pole takes such variances into consideration. SCE does not relate its projected cost per pole to any particular percentage of rural work. In light of the low 2004 recorded cost per pole replacement, SCE showing does not support its forecasted replacement cost of $18,400 per pole. We will instead average the two costs, the $18,400 projected by SCE in 2004 dollars and the 2004 recorded cost of $14,197 to approximate the cost per pole for 2006, in 2004 dollars. This results in a cost per pole of $16,300, and reflects a lower percentage of rural pole replacements in 2006 than in 2004. Adjusting SCE's forecast, by the reduced cost per pole, results in our adopted test year 2006 forecast of $17,939,000 as opposed to SCE's request of $20,100,000.

18.21 Distribution Automation

Distribution Automation is an ongoing program to provide remote control and monitoring of various distribution devices, such as mainline distribution switches, automatic reclosers, fault indicators and capacitor banks. This is accomplished by installing controllers incorporating intelligent electronics and a wide area packet radio communication system to operate distribution equipment and provide real-time information to system operators and engineering personnel.

There are three ongoing distribution automation capital projects:

- Capacitor Automation or Programmable Capacitor Controls;
- Circuit Automation, and
- Distribution System Efficiency Enhancement Project.

At issue in this proceeding is the forecast of costs related to circuit automation. SCE forecasts $5,900,000 for 2005 and $6,100,000 for 2006. For all

three distribution automation projects, SCE requests $12,900,000 in 2005 and $13,400,000 in 2006.

DRA believes SCE's forecast for circuit automation is unreasonable and recommends a reduction based on its installation forecast for the total number of underground and overhead remote control switches, as well as the unit cost calculation for these items and remote transmission switches and remote fault indicators. DRA recommends expenditure levels of $3,700,000 for 2005 and $3,800,000 for 2006. For all three distribution automation projects, DRA recommends $10,700,000 in 2005 and $11,100,000 in 2006.

In rebuttal, SCE claims that contrary to DRA's assertions, the material costs for automation are in line with unit prices used in SCE's cost calculation for each type of automation equipment; DRA has incorrectly compared average customer minutes of interruption (ACMI) reductions for SCE's circuit breaker replacement program to the distribution automation program, DRA uses inconsistent recorded data to arrive at its forecast for remote control software and circuit automation; and DRA's distribution reliability proposal takes credit for SCE's proposed distribution automation program, which DRA's capital expenditure recommendation would largely disallow.

18.22 Discussion

SCE has provided information in rebuttal that shows its vendor contract prices are not two-to-three times lower that that used in its cost calculations as claimed by DRA. The vendor contract prices appear to be in line with those assumed in SCE's automation cost calculations. SCE also makes relevant observations regarding ACMI comparisons, DRA's use of inconsistent recorded data and assumptions related to DRA's proposed reliability mechanism.

However, DRA's use of recorded data to forecast future expenditures is not misplaced, especially in light of the significant proposed increases in this program from the 2003 recorded amount of $3,141,000 to SCE's $6,100,000 forecast for 2006. Also, SCE's recorded amount for 2004 of $3,400,000 is less than the $5,804,100 forecast as part of this GRC. While SCE argues its forecasts are better because it accounts for such things as differences between the current and future mix of overhead and underground equipment, its forecasts can be affected significantly by other factors such as limitation of workforce and prioritization of projects which may overwhelm such planning precision.

A five-year average of historical costs for the period 1999 – 2004, excluding 2001, would provide a reasonable forecast based on fairly recent, applicable information. In rebuttal, SCE indicates if that average were escalated the result would be $4,800,000.[101] We will include this amount for the test year forecast of circuit automation expenditures. The adopted test year forecast for the three ongoing distribution automation projects is then $12,100,000.

18.23 Replacement of Substation Capital Equipment

SCE requests capital expenditures in two major categories – Substation Capital Replacements and Other Capital Requirements. Substation Capital Replacements expenditures are further divided into two sub-categories - Substation Infrastructure Replacement Program (SIRP) and Routine Capital Replacements. The SIRP focuses on a proactive, planned replacement of aging infrastructures for the purpose of minimizing safety risk to employees and the general public, maintaining system reliability, and reducing

[101] SCE/Exhibit 96, p. 81.

O&M costs. Routine Capital Replacements, on the other hand, are expenditures for the purpose of improving substation infrastructures, including routine and reactive replacements of equipment due to failures and normal maintenance. Other substation apparatus not covered under the SIRP are also included in this category.

Other Capital Requirements covers forecast expenditures for tools, spare parts and equipment, facilities, furniture and office equipment, and other miscellaneous items such as easements.

DRA states that SCE has failed to demonstrate that its request is reasonable and necessary. DRA's recommendations for 2005 and 2006 are consistent with historical spending.

18.24 Discussion

Discussions related to each of the substation projects in dispute follow. As discussed earlier in this decision, we will address issues as they relate to test year 2006 costs only. We will be incorporating 2005 recorded information into this proceeding via SCE's filing in 2006. In the meantime, we will include SCE's forecast of capital expenditures for 2005.

Also as discussed earlier in this decision, in general SCE has provided information that supports a need to replace certain portions of its distribution infrastructure at rates in excess of recorded rates. This also applies to substation element of its infrastructure replacement program. Again, we will evaluate SCE's requests for the various aspects of its proposed infrastructure replacement program with that in mind. However, SCE still has the burden to justify the need and costs of each of its various proposed elements of the program.

As discussed below, we have evaluated SCE's test year 2006 proposals for replacement of substation capital equipment and considered DRA's recommendations in developing the test year forecasts. For the amounts at issue, SCE requests $127,800,000 for 2006, while DRA recommends an amount of $49,500,000. We adopt a test year 2006 forecast of $84,400,000.

18.24.1. Distribution Circuit Breaker Replacement Program

SCE forecasts expenditures of $16,100,000 in 2005 and $22,600,000 in 2006 to replace 130 distribution circuit breakers in 2005 and 187 in 2006. From 2004 to 2008, SCE plans to replace about 211 distribution circuit breakers per year, equivalent to a 50-year replacement cycle.

DRA is recommending the continuation of historical work and expenditures because of its belief that SCE has not justified its forecast. DRA states that while SCE claims that age, those circuit breakers 40 years and older, is a determinant factor in the replacement of the circuit breakers, between 1997 and 2004, out of a total of 1,344 distribution circuit breaker replacements, 628 or 43% were under 40 years of age. DRA's recommendation of $12,200,000 for 2005 and $22,600,000 for 2006 is based on averages of 2002 – 2004 expenditures.[102]

18.24.2. Discussion

In rebuttal testimony, SCE provided age demographic information on circuit breakers. SCE claims that information shows that while a significant number of circuit breakers were replaced below the age of 40, most were in the older part of that range. The data shows that of the 1624 circuit

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[102] *See* Comparison Exhibit, Exhibit 899, p. 337. In its opening brief DRA, p. 107, DRA states that it recommends $9,900,000 per year based on an average of 1999 – 2004 expenditures. For discussion, we will use DRA's Comparison Exhibit recommendation.

breakers removed from service, 44% were aged 41 years or older, 12% were aged between 36 and 40 years, and 11% were aged between 31 and 35 years. In general, we would agree that there is a greater likelihood that older rather than newer circuit breakers will be replaced. However, it is not clear why SCE's estimate of 187 circuit breakers to be replaced at a cost of $22,590,000 is reasonable. It is not clear, that at this time, a 50-year replacement cycle is necessary.

SCE has provided information on its aging circuit breaker population and technical reasons why certain circuit breakers may be prone to failure. However, while the circuit breaker replacement program appears to be successful in decreasing the average customer minutes of interruption (ACMI) since 1997,[103] it was done with average expenditures of approximately $9,000,000 per year. SCE spent $12,605,000 in 2002, $14,650,000 (including $4,352,000 for the Santa Monica Substation) in 2003, and $11,800,000 in 2004 on the distribution circuit breaker replacement program. SCE attributes lower spending in 2002 and 2003 to residual effects of the energy crisis and prioritization of projects. This may be true, but the necessity of spending at the significantly higher level of over $22,000,000 per year has never been demonstrated, even during years in which SCE's infrastructure replacement program was in effect. However, due to the potential benefits of this program in reducing interruptions to customers as well as O&M expenses, we will include expenditures for 2006 based on SCE's forecast for 2005. 2003 recorded information shows SCE's commitment to spend at least $14,650,000, even if a large portion was just for the Santa Monica substation. The

[103] Since this program has been established, SCE's ACMI measurement has decreased from 1.452 minutes per year to 0.5 minutes per year.

2005 forecast of $16,100,000 is in the range of the 2003 recorded amount which is about $15,100,000 in 2005 dollars. We see, however, no justification to increase the 2006 adopted amount to the $22,600,000 requested by SCE.

18.24.3. Transformer Replacement Program A-Banks

SCE replaces transformers both proactively, that is, before in-service failure and reactively, that is, after failure in-service. SCE reiterates that replacement prior to imminent failure is one the main goals of its infrastructure replacement program, since it mitigates outages and the resulting costs to customers. SCE's A-Bank Replacement Program starts with expenditures of $25,500,000 in 2006, which is planned to allow replacement of 12 A-Bank transformers in that year. SCE indicates that it plans to replace a total of 46 A-Bank transformers by 2008. The 46 transformers were identified by a group of company experts assembled to rate the transformers for replacement. The group known as the Transformer Resource Management Committee (TRMC) looked at the following factors that contributed to in-service failure: (1) age, (2) manufacturer, (3) design, (4) dissolved gas analysis, (5) loading/fault history, and (6) maintenance history.

According to DRA, between 1989 and 2003, SCE experienced a failure rate of 0.9 per year or an average of 13 months between failures. Based on its perception of a lack of support for SCE's forecast, DRA used A-Bank replacement history to determine the forecast for 2006. Based on recorded number of projects and the total cost for A-Bank transformer replacements from in 2000-2002, DRA forecasts two replacements for 2006 at a total cost of $2,000,000.

18.24.4. Discussion

SCE has provided information that shows that the average age of the transformers it plans to replace is 52 years, which is significantly higher than both the nominal design life of 20.55 years identified by the IEEE and the historical average age at replacement of 42 years. This justifies the need to consider increased proactive replacements of A-Bank transformers in the future. However, in recent years SCE has replaced only two A-Bank transformers per year proactively. In 2004, three transformers were replaced due to in-service failures. While the recommendation to replace 16 transformers in 2006 is based on the recommendations of a group of company experts who rated the transformers for replacement, we are not convinced that such a drastic increase from the recent experience of two per year is necessary.

SCE indicates that DRA's recommended two replacements per year would amount to a replacement cycle of more than 100 years, more than five times the transformers nominal design life. We will authorize 10 replacements per year which would then result in a replacement cycle close to the nominal design life. Additionally, we will reduce the cost per transformer from $1,700,000 to $1,500,000 in consideration of recent recorded unit costs that averaged about $1,000,000 and which were used by DRA in its estimate. SCE did provide cost estimate detail, which showed the cost of the transformer itself was about $1,000,000, but it did not explain why the recorded costs were so low. Our adjustment to the average unit cost merely reflects the possibility that circumstances which occurred during the last three-years may occur in the future and result in costs less than estimated by SCE. Based on this discussion, we adopt a forecast of 10 A-Bank transformer replacements at a cost of $15,000,000 in test year 2006.

18.24.5. Transformer Replacement Program B-Banks

Failures of B-Bank transformers averaged 6.5 per year from 1993 to 2003. In 1998, SCE conducted an analysis of B-Bank transformers using the TRMC methodology. Of the initial 50 units assessed, six were identified for replacement. SCE later assessed an additional 150 units and based on the same TRMC methodology, planned to replace seven in 2004, 14 in 2005, 13 in 2006, 14 in 2007 and 13 in 2008. The forecasted expenditures for 2006 amount to $6,600,000.

DRA states that SCE only replace four transformers in 2004 at a cost of $2,900,000. None were replaced in 2001 and 2002. Also, DRA indicates that the 1998 TRMC identified six replacements but SCE identified 15 units for replacement as part of this GRC. DRA states that the available TRMC data shows that only nine units need to replaced and DRA has reason to believe all nine units have already been replaced. Based on its analysis, DRA recommends $0 for B-Bank transformer replacements for 2005 and 2006. DRA asserts that SCE should have embedded expenditures from previous GRCs for transformer replacements on as-needed basis.

18.24.6. Discussion

In rebuttal testimony, SCE clarified that in 2004, it replaced seven transformer banks at a cost of $2,900,000. Also, DRA has apparently confused identification of units for the replacement plan analysis and the units replaced. SCE states that while the initial analysis in 1998 identified 15 units for the replacement plan, by 2001 it had performed analysis on 212 units. SCE also provided information on DRA concerns regarding the planned year of replacement and identification of units replaced under the substation infrastructure replacement program.

SCE has provided information that shows the ages of the units scheduled for replacement in 2005, including seven that are 81 year old, three that are 78 years old and six that are 77 years old. This justifies the need to consider increased proactive replacements of B-Bank transformers in the future. When considering an average of 6.5 failures per year and the replacement of seven banks in 2004, SCE's forecast of 13 B-Bank transformer replacements in 2006 appears reasonable. We adopt SCE's test year forecast of $6,600,000 for this program.

18.24.7. Distribution Protection and Control Replacement Program

SCE states that the protection and control systems at many of its 900 substations are aging. The age of the equipment ranges from 30 - 100 years. The aging protection and control systems are made up of electro-mechanical devices such as relays and switches, which require routine testing, maintenance, and repair. This equipment has no self-monitoring capability and no remote monitoring or control functions. The modern protection and control equipment SCE is using provides self-monitoring as well as remote monitoring and control of all functions and will identify potential problems before they cause harm. Through its automation program, which ended in 2003, SCE has replaced the protection and control equipment in 187 substations. There are still over 700 stations with the old electro-mechanical equipment, which this program is designed to replace. SCE began this program in 2001 with engineering, design, and procurement. Construction on the first project began in 2003. The program is intended to be ongoing, with approximately 25 substations being retrofitted each year. SCE forecasts expenditures of $14,750,000 associated with 25 projects in 2005 and $14,880,000 associated with 25 projects in 2006.

DRA disagrees with SCE's projected 25 projects per year in 2005 and 2006 as well as unit cost of the replacements. DRA recommends using the escalated three-year average of the 2002-2004 expenditures and the actual number of substations replaced, as the basis for the 2005 and 2006 forecast. DRA's calculations yield an annual forecast of 17 substations with costs of $6,200,000 in 2005 and $6,400,000 in 2006.

18.24.8. Discussion

The distribution protection and control replacement program appears to be replacing the Substation Automation Program which ended in 2003. In that respect, we can consider these activities as continuing in nature. What is not clear is whether the programs are comparable as to the number of protection and control replacements per year or the magnitude of the expenditures related to the replacements. While SCE points out it has over 700 substations with old electro-mechanical equipment, it has not provided much information on failures associated with such equipment or quantification of other factors which would justify a need to replace protection and controls at 25 substations per year in 2005 and 2006. A program of replacement as suggested by SCE is reasonable but there needs to be some specific information on the impacts of carrying out the program at increased or reduced levels in order to make a decision on what the adopted level should be. SCE has not provided information on why its request of 25 substations per year is better than the historical average of 17 recommended by DRA. As a compromise, we will adopt 21 as the number of substations for the distribution protection and control replacement program for 2006.

Regarding costs, SCE states that costs of each substation are driven by the protection requirements of each piece of substation equipment. On

the other hand, SCE has not addressed the specific reasons why the recorded units costs of $376,000 (in 2006 dollars) recommended by DRA are so much lower than its engineering estimates that average $595,000 per unit for 2006. Again, as a compromise, we will use the average of the two unit cost estimates, or $485,000, to forecast costs for this program. We adopt a forecast for distribution protection and control replacement at 21 substations with expenditures amounting to $10,185,000 for test year 2006.

18.24.9. A/AA Control Room Upgrade

SCE states that the A/AA Control Room Upgrade and Replacement Program will provide control of seven of its large attended stations by replacing the existing manual controls and indicating devices with a networked system. The new system will make it possible to locate the system operator's workstation at any location, not just in close proximity to the manual controls. It will also make it possible to monitor and control these critical facilities from a remote location in the event that the local control room becomes un-inhabitable. SCE proposes expenditures of $7,500,000 in 2005, 5,800,000 in 2006, $360,000 in 2007, and $2,000,000 in 2008.

DRA states that SCE could not provide any support for the forecast and claimed that "the numbers in this table were arrived based on conceptual estimates." DRA indicates that SCE could only provide support for one project, that of the Villa Park substation and recommends that only this project be included in the 2005 and 2006 forecast. DRA recommends funding of $1,000,000 for each of the years 2005 and 2006.

18.24.10. Discussion

While DRA does not appear to contest the need for this program, it challenges SCE's estimated costs alleging that SCE was unable to

provide support for those estimates. SCE argues that it provided the cost breakdown in the same level of detail provided for the Villa Park and Mesa projects and that DRA simply asserts that SCE's costs estimates, which were based on industry accepted standard engineering methods are not acceptable while offering no objective alternatives. We agree with SCE on this point. If DRA disagrees with the estimating methodology, it should at least explain the problem so that we can determine the soundness of SCE's showing. If possible the suggestion of an alternative methodology would be helpful. Lacking this type of information, we will adopt SCE's estimate of the costs for this program. We note that until detailed engineering and design is performed, use of industry accepted standard engineering methods may be appropriate for estimating future costs. For ratemaking purposes, we will normalize the costs for this program over the GRC cycle 2006 - 2008. This results in an average expenditure of $3,800,000 which we will adopt for test year 2006.

18.24.11. Substation Equipment Reactive Replacement Program

This program addresses estimated expenditures to replace substation equipment and major equipment that fail while in service or as a result of inspections showing the risk of imminent failure. SCE uses a four-year average of recorded expenditures for the period 1999 – 2003, excluding 2001, to forecast a base. On top of that base, SCE adds adjustments for Butyl Current Transformer Replacement, Cable Trench Cover Replacement, Disconnect Switch Replacement and Environmental Remedial Action, forecasted expenditures not previously identified in this blanket. For this reactive replacement blanket, SCE forecasts expenditures of $26,800,000 for 2005 and $32,900,000 for 2006.

DRA disagrees with SCE's calculation of the four-year average. DRA also disagrees with SCE's adjustments related to Butyl Current Transformer

Replacement, Cable Trench Cover Replacement, and Disconnect Switch Replacement. DRA's estimate of $17,700,000 for 2005 and $18,200,000 for 2006 is based on the escalated four-year average for 1999 – 2003, ($15,600,000 in constant 2003 dollars as opposed to SCE's calculation of $24,300,000 in 2003 dollars). DRA's estimate also includes environmental remedial action costs as requested by SCE.

18.24.12. Discussion

Regarding the four-year average, DRA opposes SCE's "adjustment" of historical costs through the inclusion of estimated expenditures for transformer bank replacements from 1999-2001, and expenditures for "Other Specific Engineered Projects" from 2001-2003. DRA argues that SCE artificially inflated the average. In rebuttal, SCE states:

> As an initial matter, SCE did not inflate the historical averages, but adjusted the recorded cost to properly account for all reactive replacement expenditures. Prior to 2002, a portion of reactive replacement activities, such as those involving greater degree of complexity in project scope (for example, the replacement of a failed A-Bank transformer) were funded by offsetting this reactive blanket against another budget item (such as SIRP), resulting in the reduction in the recorded expenditure in this reactive blanket.
>
> This same budget offset was also used on other reactive replacement projects of significant scope (*i.e.,* more than a simple like-for-like swap-out) that required engineering and design work. In these cases, SCE's Project Management Organization manages those projects and blanket budgets are offset by the expended capital amount. Again, this

> effectively reduces historical expenditures in these blanket budgets for reactive replacement of greater complexity.[104]

SCE explains why the recorded amounts in this blanket are reduced, but it is not evident that future blanket costs will not be offset against other budget items or offset by expended capital amounts of projects managed by SCE's Project Management Organization. Without such evidence, it is reasonable to assume that some offsets to this blanket will continue to occur. Therefore, we see no reason to add offset costs back into the blanket in determining an average for forecasting test year 2006 and will adopt the four-year average as calculated by DRA. This results in a 2006 base of $15,600,000 in 2003 dollars, or $17,600,000 in 2006 dollars.

SCE adds four adjustments to the base for forecasted activities that are not reflected in the historical data and therefore not in the four-year average. DRA objects to three of the adjustments, as discussed below.

DRA objects to the inclusion of $600,000 for butyl current transformer replacements, because SCE could not provide support related to a 1987 survey and information related to a more recent survey was incomplete. In response, SCE states that it provided condition codes based on actual inspection results of the butyl current transformers in the substations, which should be sufficient to identify the problem.

SCE shows this cost to be in 2005. As discussed previously, we will be incorporating 2005 recorded information into this proceeding via SCE's CAAM filing in 2006. In the meantime, we will include SCE's forecast of capital

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[104] SCE/Exhibit 96, pp. 126-127.

expenditures for 2005. To the extent that the work is actually done, it will likely be included in rates. In any event, it appears that problems with butyl current transformers have been identified, perhaps as long as 17 years ago, and it is reasonable to replace them as proposed by SCE.

DRA objects to the inclusion of $1,600,000 per year to replace cable trench covers, principally because of its understanding that these costs are embedded in historic data and thus a certain level are already included in the base. In response, SCE states:

> In response to DR-ORA-45, we provided detailed information on the expenditure in FERC Subaccount 570.400 to replace deteriorated redwood cable trench covers with new redwood covers. The reactive replacement information for the distribution substations is not included in the discussion of Subaccount 570.400 which only covers transmission substations. Thus, DRA's claim that the proactive replacement program proposed for 2006 is similar to the reactive program in 2001 and 2002 is based on incomplete information. ORA's testimony fails to recognize the scope of SCE's proactive approach regarding the safety of its employees. ORA assumes that the historical rate of replacement was sufficient to address the replacement need going forward.
>
> ORA failed to recognize that during recent years SCE has been in the process of developing a new trench cover with enhanced durability. While this development was taking place, SCE used redwood trench covers on an <u>interim</u> basis to replace trench covers that had failed and this historical replacement rate was insufficient to address the

> safety concerns of the increasing number of deteriorated trench covers.[105]

SCE's explanations are sufficient to justify it request for cable trench cover replacement and we will include $1,600,000 for this activity in test year 2006.

Lastly, DRA objects to the inclusion of $3,000,000 per year to replace disconnect switches, because SCE could not provide support for the number of switches it proposes to replace. In response, SCE states that it has provided sufficient information through its exhibits, workpapers and data request responses to support its request.

SCE's testimony identifies a need to establish a systematic method for identifying high risk disconnects for replacement, indicating that the present method for identifying disconnects for replacement is a reactive process. The testimony itself does not provide any quantification or indication of the magnitude of the perceived problem. A data request response (Exhibit 237) referenced in SCE's rebuttal provides unit cost information. The response also indicates that historic data related to the number of disconnect switches repaired and replaced was not available. Also, it does not appear that any workpapers supporting SCE's requested number of disconnect switch replacements were offered in evidence. In concept, SCE's request is reasonable, but without any justification for the level of activity proposed, we must reject funding for this program.

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[105] SCE/Exhibit 96, p. 129.

Based on the discussion above we adopt a forecast of $19,800,000. This includes $600,000 for environmental remedial action to which DRA did not object.

18.24.13. Rule 20B Circuit Breaker Replacement

SCE explains that older circuit breakers may not meet newer operational requirements. A number of the older 66 kilovolt (kV) and 115kV class circuit breakers are incapable of de-energizing underground cable beyond a certain length. When the Rule 20B projects cause the cable to exceed this length, the circuit breaker must be replaced. Based on an average of 1999 – 2002 costs, SCE includes $2,200,000 in 2005 and $2,300,000 in 2006 for this activity.

DRA states that SCE did not justify its request and uses a three-year average of 2002 – 2004 costs to calculate its estimate $300,000 per year.

18.24.14. Discussion

In response to DRA's recommendation, SCE states that the use of a four-year average based on the years 1999 – 2002 and adjusted for inflation is consistent with its proposal for subtransmission capital expenditures for Rule 20B projects. SCE argues that DRA's forecast is inappropriate because (1) the accounting for Rule 20B circuit breaker replacement changed recently and (2) 2003 was abnormally low and not representative of future spending needs.

SCE has sufficiently explained the basis for it proposed averaging of 1999 – 2002 data to forecast Rule 20B circuit breaker replacement costs. We will adopt the company's estimate of $2,300,000 for test year 2006.

18.24.15. Overhead Line Additions and Replacements

The only area at issue here is SCE's request for an additional increase of $1,900,000 above historical spending levels, which breaks down to $100,000 in 2004 and $1,800,000 in 2005, to construct three access bridges for the

flood control channels that bisect its Mesa-Antelope 220 kV line right-of-way along Interstate 605 Freeway. SCE claims that this requirement is the result of an agreement with Caltrans and accounts for the high forecast in 2005. DRA opposes this portion of SCE's request because it cannot verify the need.

The costs for this project appear in 2004 and 2005. As discussed previously, we will be incorporating 2005 recorded information into this proceeding via SCE's CAAM filing in 2006. In the meantime, we will include SCE's forecast of capital expenditures for 2005. To the extent that the work is actually done, it will likely be included in rates.

18.24.16. Tools, Spare Parts, and Equipment

This work category tracks expenditures for three budget items: (1) the Grid Dispatch Annual Department Program, (2) Tools and Work Equipment, and (3) Substation Spare Parts and Equipment. SCE's forecasts are a combination of averaging and budgeting and amount to $8,000,000 for 2005 and $9,100,000 for 2006.

DRA states that the 2005 request is almost twice, and the 2006 request is more than twice, the actual expenditure of $4,300,000 recorded for 2004. Also, SCE spent $2,400,000 less than its original forecast of $6,700,000 for 2004. SCE explains that the 2003 and 2004 expenditures were abnormally low because the company had a low number of failures in substation B-Banks, but that the company is anticipating a greater likelihood of failure in the future. DRA investigated the need to purchase additional power transformers to maintain an adequate inventory of spares, but was unable to determine whether or not additional transformers are needed or determine the cost to acquire these transformers. DRA based its estimate of expenditures on an escalated three-year average resulting in $4,900,000 for 2005 and $5,000,000 for 2006.

18.24.17. Discussion

Costs for this category have varied significantly over time, generally showing a downward trend since 1999. An average of recent years escalated to test year dollars would provide a reasonable estimate. Because of the energy crisis, 2001 has generally been excluded from averages in this proceeding. For tools and grid dispatch, we will use an average of the post energy crisis years of 2002 and 2003.[106] This results in tools cost of $4,000,000 and grid dispatch costs of $300,000 for the test year. For spare parts, SCE links the test year amount to B-Bank transformer replacements. DRA was unable to substantiate that need. However, since we have, in this decision, adopted SCE's capital request regarding B-Bank transformer replacements will therefore include costs of the related spare parts, which amount to $3,600,000. Our adopted total test year forecast for this category is therefore $7,900,000.

18.24.18. Furniture, Equipment and Facilities

For the Non-Operational Facility Blanket, SCE plans to expend $5,000,000 in each of the years 2005 and 2006 for facility expansion and improvements, including new office spaces, permits and building additions, office reconfigurations, etc. SCE states the funds are necessary to meet the incremental facility requirements of the T&D business unit. These funds are for potential locations and scope additions not included in the Corporate Real Estate (CRE) business unit capital budget.

Based on SCE's statement that the $5,000,000 was a blanket allowance of funds without itemized estimates and DRA's understanding that

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[106] DRA references 2004 recorded information, but does not provide the necessary detail for use in this analysis. Therefore, only 2002 and 2003 recorded data is used.

SCE has never recorded any spending under this category, DRA concluded that SCE has provided no justification for the expenditures and therefore recommends $0.

18.24.19. Discussion

In rebuttal, SCE argues that DRA ignored a data request response that showed details on increases in employees and impacts on availability of office space and facilities. SCE states that from 1999 to 2004 total head count with direct impact to facility need grew from 4,328 to 4,853. SCE also describes the San Jacinto Service Project that was included in its CRE testimony. Given increased numbers of employees, SCE has still not explained why the CRE budget cannot accommodate its facility growth needs, as specific facility needs are identified. For example, for shared services capital projects over $1,000,000, SCE lists a number of projects totaling over $100,000,000 in direct costs with operational dates from 2004 to 2008. Included in the list are the San Jacinto Building Addition and other facilities used by the T&D business unit. SCE has not justified including funds for other, potential projects or addressed DRA's concern that no money has ever been spent in this category. We will therefore not include any funding for the non-operational facility blanket.

18.24.20. Fee Simple and Rights-of-Ways

The Fee Simple and Rights-of-Way category is to acquire real properties and rights-of-way that are necessary for our transmission and substation system expansion due to load growth. SCE's estimate is based on its expected property and right-of-way needs for the 2004 – 2008 timeframe and result in estimates of $3,900,000 in 2005 and $500,000 in 2006.

Based on its analysis of SCE's expected needs, DRA states:

> ORA has reviewed SCE's supporting documents for this work category. According to responses to ORA

> data requests, SCE has not yet begun work on the Oak Valley acquisition project. The Akers and Canine projects currently have no supporting data to show that these projects will be completed in the year forecasted. It appears that SCE has not yet located potential substation sites for the Akers project and that the target date for this project, January 28, 2005, has not been met. As for the Canine project, SCE provided no supporting data at all for this acquisition. Finally, ORA learned that the Las Lomas acquisition is currently on hold pending a municipalization decision by the City of Irvine. As such, SCE will not need any of the requested capital expenditures it has previously requested.[107]

DRA concludes that none of the requested expenditures are necessary and recommends $0.

18.24.21. Discussion

For 2006, SCE has included $500,000 associated with the Oak Valley project which SCE addresses in its load growth testimony. Since DRA has not opposed the project, we will include the fee simple/rights-of-ways costs in 2006 as requested by SCE.

For the remaining projects at issue, the costs fall in the year 2005. As mentioned previously, we will be incorporating 2005 recorded information into this proceeding via SCE's CAAM filing in 2006. In the meantime, we will include SCE's forecast of capital expenditures for 2005. To the extent that SCE meets its expected needs for fee simple and rights-of-ways costs in 2005, those expenditures will likely be reflected in rates.

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[107] DRA/Exhibit 202, p. 13-D-68.

19. Rate Base – Other than Plant in Service

19.1. Ratemaking Treatment for Fuel Inventories

SCE proposes that its fuel inventories be split into permanent and temporary components with separate ratemaking for each. The permanent component would be included in rate base and treated as a long-term asset financed with a combination of debt, common equity and preferred equity. SCE's test year estimate for the permanent fuel inventory to be included in rate base is $88,107,000.

SCE recognizes that in its 1995 GRC, the Commission denied a similar request.[108] However, SCE submits that circumstances have changed since that decision was issued that allow for the inclusion of permanent fuel inventories in rate base. In the 2003 GRC decision, the Commission found that a permanent level of customer deposits was available for working capital. The Commission now requires SCE to rely on customer deposits as a permanent source of financing for a portion of rate base. SCE argues that since the Commission has changed its policy regarding the use of customer deposits, it is only proper to now revisit the fuel inventory issue. It is SCE's position that, if customer deposits are to be considered a credit to rate base, it is reasonable and fair as a matter of policy to provide parallel treatment for the permanent portion of fuel inventories and permanently finance them by adding them to rate base.

In support of its position, SCE notes that the Commission continues to treat natural gas inventories held by gas distribution companies using the

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[108] *See* D.96-01-011, *mimeo.*, p. 226.

same method SCE proposed for it fuel inventories. Also, FERC policies include in rate base the fuel inventories at issue in this proceeding.

Currently all of SCE's fuel inventory costs are recovered annually through ERRA proceedings. According to DRA, SCE's current cost recovery method for fuel inventory through annual ERRA proceedings, results in a total cost of $7,000,000, while under SCE's proposed fuel inventory cost recovery method of permanently adding a portion of fuel inventories to rate base, the total cost would be $14,900,000. DRA opposes SCE's proposal to rate base a permanent portion of inventory given the historical treatment of the costs and that SCE's proposal increases cost with no benefit.

Regarding SCE's claim of changed circumstances, DRA states that there is no direct link, within the policy regarding customer deposits, to justify altering the handling of fuel inventories.

19.2 Discussion

We are not persuaded to change the current ratemaking treatment for fuel inventory. There is a long history to this issue.[109] Following are a few excerpts from relevant decisions.

In D.85-12-107, the Commission first addressed the question of proper rate treatment of fuel inventory for SCE.

> Edison no longer shall be allowed to charge ratepayers the cost of carrying fuel oil in inventory at the authorized rate of return. There are several reasons for this. First, the authorized rate of return includes equity and long-term debt. The cost of using equity rather than debt is higher to the ratepayer because of the income tax

[109] D.96-01-011, 64 CPUC2d 241, 356, provides a detailed history of the ratemaking treatment of SCE's fuel inventory carrying costs.

> that must be recovered with a return on equity. Second, the balancing account associated with the ECAC expense was not designed to reward the company with its rate of return on a non-rate base item but to shield the company from wide swings in fuel expenses. Finally, the low-risk nature of fuel oil inventories call for a different ratemaking approach.[110]

The Commission concluded:

> Fuel oil inventory is low risk. Unlike rate base assets, fuel oil inventory is subject to balancing account treatment. In effect, Edison (SCE) has been guaranteed recovery of its rate of return on a low-risk asset. This result was never intended to occur through ECAC procedures.[111]

In D.87-12-066, the Commission extended the above holding to SCE's coal and nuclear fuel inventories. The Commission stated:

> Although Edison (SCE) points out that the operating and life cycle characteristics of nuclear fuel are not the same as coal, gas, and oil, we believe that this is not enough to warrant a different ratemaking treatment. In fact Edison (SCE) proposes to finance nuclear fuel with a combination of short and intermediate-term debt. While this might indicate that there is a need to factor in the cost of intermediate debt in deriving the carrying cost associated with nuclear fuel, it does not justify rate base treatment.[112]

The Commission further stated it preferred the use of short-term debt instruments to determine carrying charges on fuel. Because fuel "is a commodity that can be used as collateral for financing and is distinguishable from fixed plant

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[110] D.85-12-107, 20 CPUC2d 111,112, as modified in D.86-05-095, *slip op.* at p. 2.

[111] *Id.*, at p. 3.

[112] D.87-12-066, 26 CPUC2d 392.

and land…fuel should not be afforded rate base treatment, regardless of its characteristics."[113] The Commission directed SCE to calculate carrying costs on its unspent nuclear fuel and coal reserves using the cost of short-term debt, and continue to include these costs in its former ECAC (now ERRA) balancing account.

In D.96-01-011, the Commission denied SCE's previous proposal to split fuel costs into permanent and temporary portions and disagreed with the permanent inventory level concept, stating it did not believe the increased risk SCE was willing to assume was significant enough to justify a change in financing. The Commission also stated:

> We believe it more efficient to include determinations of the reasonableness of fuel inventory levels in the ECAC proceedings. That proceeding engages fuel experts who review the utility's fuel purchasing policies as a whole. Taking out one piece of that puzzle for general rate case review may result in an incomplete analysis of fuel practices.[114]

SCE has not provided sufficient reason for us to change the current ratemaking policies for fuel inventory as described and justified above. SCE does state that the Commission's decision, in SCE's 2003 GRC, to include customer deposits as a rate base deduction is reason to reconsider the issue in this proceeding. We disagree. In D.04-07-022, we stated the following:

> 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

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[113] *Id.*

[114] D.96-01-011, 64 CPUC2d 241.

> 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, Findings 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.[115]

Nothing has changed. The reasons why we rejected rate base treatment for fuel inventory has nothing to do with the reasons why we included customer deposits in the operational cash requirement analysis. Fuel inventory was excluded from rate base because of the cost to ratepayers, the balancing account treatment for fuel expenses and the low risk nature of fuel inventories. Inclusion of customer deposits in the operational cash requirement is not new. Non-interest bearing customer deposits have always been included. SCE however pays interest on customer deposits, so prior to D.04-07-022, its customer deposits were excluded in developing the operational cash requirement. The Commission, in D.04-07-022, instead compensated SCE for the interest it pays on customer deposits and estimated a balance of funds that would be available to offset the operational cash requirement. The result was reduced overall costs to ratepayers, while SCE was fully compensated for the interest costs that it paid.

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[115] D.04-07-022, *mimeo.*, 254-255.

The Commission's determinations regarding fuel inventory and customer deposits are consistent, in one respect. That is, changes were made to existing practices, which resulted in reduced rates while still providing SCE a fair opportunity to recover its costs. These results are consistent with our responsibilities, in general, and we see no reason to alter the currently adopted ratemaking associated with either issue.

19.3 Materials and Supplies

For Materials and Supplies (M&S), SCE used an inventory turnover method to forecast the balances for this GRC cycle. This methodology is based on the level of material-related expenditures flowing through the M&S inventory and the inventory turnover rate. SCE developed different turnover rates for T&D M&S and Generation and Base M&S. SCE indicated that the T&D M&S inventory turned over at a rate of about 4.4 times per year. SCE then applied this turnover rate to the annual M&S expenditures flowing through inventory to estimate test year 2006 M&S inventory level attributable to Transmission and Distribution projects. SCE determined that its generation related M&S inventory had lower turnover rates than T&D and the balances were expected to be more stable, with a slight annual decrease projected for the GRC period. SCE's resultant test year estimate of $146,677,000 also reflects its agreement with TURN's proposed adjustment to reflect sales tax deferrals associated with Edison Material Supply, LLC.

Because the Commission, in SCE's last GRC, determined that SCE could not establish any direct and proportional relationship historically between the M&S inventory level and plant additions, and because SCE's M&S inventory appeared to drop from $139,504,000 in 2003 to $131,419,000 in 2004, DRA recommends that the Commission reject inventory turnover as a appropriate

method to estimate the test year 2006 M&S balance. DRA recognizes SCE's increasing efforts to optimize M&S inventory and increasing resources, such as the Material Management System, to do so. Because of this, DRA expects the M&S inventory level to decline in the future years as opposed to SCE's growth forecast. DRA computed a five-year (2000 – 2004) average of recorded weighted average M&S balances and used that as the foundation for its test year 2006 estimate. DRA states this is consistent with the methodology adopted in the last GRC in D.04-07-022. The DRA estimated test year 2006 Materials and Supplies Inventory is $129,511,000, which is $17,166,000 lower than the SCE's estimate.

SCE disagrees with DRA's assumption that the M&S balance decreased from 2003 to 2004. SCE asserts that DRA mistook the 2004 weighted average balance as the year-end balance. Also, in its rebuttal testimony, SCE provided corrected M&S balances to reflect sales tax deferrals associated with Edison Material Supply, LLC, which shows the M&S weighted average balance increased from $126,163,000 in 2003 to $131,419,000 in 2004.

19.4 Discussion

SCE has provided sufficient evidence to show that the M&S balance increased from 2003 to 2004. The corrected historic weighted average balances are as follows:

1999	$111,955,000
2000	$113,956,000
2001	$116,652,000
2002	$119,339,000
2003	$126,163,000
2004	$131,419,000

The average annual percent change is 3.3%. It appears the M&S inventory is continuing to grow as SCE increases its capital and project

expenditures in the TDBU. However, in revising it M&S forecast to reflect the corrected historic information, SCE forecasts a 2004 weighted average balance of $137,317,000 which is 8.8% above the recorded 2003 balance and 4.5% above the recorded 2004 balance. This indicates there may be a problem with SCE's inventory turnover method. It is possible that increasing efforts and resources to optimize M&S inventory have not been fully factored into SCE's forecast.

To forecast the test year M&S balance, we will instead use the 2004 recorded balance of $131,419,000 and increase that amount by 3.3% per year, the average annual increase from 1999 to 2004. This results in an adopted test year balance of $140,236,000.

19.5 Customer Advances for Construction

SCE forecasts customer advances for construction (CAC) based upon the recorded 2003 amount and a five-year average incremental change through 2004 and construction cost inflation to project 2005-2008 balances. TURN recommends that CAC be calculated by using the 2004 year-end balance and applying construction cost inflation to project 2005-2008 balances. SCE estimates the test year 2006 weighted average CAC balance to be $66,051,000, while TURN estimates the amount to be $72,864,000.

19.6. Discussion

The difference between the SCE and TURN methodologies is in the determination of the 2004 amount upon which the cost inflation is applied. SCE forecasts the 2004 balance by applying a five-year average incremental annual change in CAC to the 2003 recorded balance. Since the recorded annual

incremental CAC changes have increased in the more recent years,[116] SCE's methodology for determining the 2004 balance appears to be deficient. SCE's end-of-year forecasts of $63,052,000 for 2004 and $67,007,000 for test year 2006 are both less than the 2004 recorded amount of $69,555,000. TURN's use of the recorded 2004 balance provides a more reasonable forecast for the test period, and its methodology will be adopted. We note however that the use of cost escalation from 2004 forward, to estimate CAC balances, may be insufficient to properly reflect the more recent recorded incremental changes to CAC balances. If appropriate, modifications to this aspect of the methodology should be explored in future rate cases.

19.7 Customer Deposits

SCE uses a five-year average of the recorded years 1999-2003 balances to estimate the permanent level of customer deposits. The estimated amount for test year 2006 is $114,919,000. SCE's methodology is consistent with that adopted in its last GRC. The use of the calculated average in light of the increasing trend in the recorded balances was a proxy to reflect the permanent level, as opposed to total level, of CAC available for financing rate base. Aglet calculated customer deposits as a percentage of average revenues for the prior two years, a proxy for deposits as a function of bills sent 12 to 24 months earlier. Aglet recommends a test year 2006 level of customer deposits equal to 1.94% of average revenues for 2004 (recorded) and 2005 (estimated), or $139,979,000. TURN supports Aglet's recommendation; but, if it is not adopted, TURN and

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[116] From 1997 to 2001, the year end balances for CAC increased from $31,619,000 to $41,270,000, or $2,413,000/year. From 2001 to 2004, the year end balances increased from $41,270,000 to $69,555,000, or $9,428,000/year. (*See* D.04-07-022, *mimeo.,* p. 241 and Exhibit 899, p. 434).)

Aglet alternatively propose that the five-year average be updated to include 2004 recorded information, resulting in a test year estimate of $127,443,000.

19.8 Discussion

Aglet's methodology is an alternative to that adopted in SCE's last GRC. In D.04-07-022, we stated that the full balance of customer deposits was unavailable as permanent capital to offset rate base. We adopted a five-year historical average as a reasonable determination of the permanent level.[117] In D.04-07-022 we explained that "permanent" amounts of customer deposits were the amounts that could be relied upon to offset rate base. SCE has characterized this to mean that the inclusion of customer deposits as an offset to rate base should represent the average base level available to SCE to utilize for permanent long term financing purposes until remitting the deposits to customers.[118]

In reconsidering the proper level of customer deposits that should be used to offset rate base, we now see no reason to exclude any of the forecasted total weighted average customer deposit amounts. Regarding such deductions

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[117] In that decision, we stated "We agree with TURN's proposal in part, but do not agree with its proposal to apply an estimated $117.174 million customer deposit balance as an offset to rate base. We accept TURN's proposal that customer deposits are a source of working capital to the utility, but not to the extent TURN would like to see earmarked as permanent. Instead, we will adopt the average amount of customer deposits over the years 1996 - 2001, as the amount that can be relied upon to offset rate base. The amount of $80 million is reasonable and should be adopted. We note that the amount of customer deposits that are available to offset rate base has the potential to change from GRC to GRC. Because we have used an average in this GRC, we expect SCE to keep the Commission informed as to the historical average of its customer deposits in the next GRC. In doing so, we will remain open to increasing or decreasing this amount based on the historical trend…" (D.04-07-033, *mimeo.,* p.255).

[118] SCE Opening Brief, p. 188.

from the operational requirement, Commission Standard Practice U-16, Determination of Working Cash Allowance, states:

> "As indicated on the lower portion of Table 3-A, there is deducted from the amount of current assets certain current liabilities which represent monies provided from sources other than the investors for the operation of the utility. These accounts may include monies already derived through rates to offset a future liability which the company has not incurred, monies received from customers for the procurement of services, and amounts withheld from employees. These amounts are intermingled in the cash balances or invested in the plant accounts. Therefore, if these amounts are not excluded, the investors in effect would be compensated for funds which they have not supplied. The following current liabilities accounts should be considered as deductions from the operational requirement."[119]

Non-interest bearing customer deposits is listed as one of the accounts that should be considered as deductions from the operational requirement. As noted above, Standard Practice U-16 does not limit the use of these monies to long term permanent financing but indicates the offset amounts are intermingled in the cash balances or invested in the plant accounts. The largest portion of the cash balances would include monies on hand to pay expenses prior to the receipt of payment from customers. Other amounts of cash may be on hand to pay dividends, debt interest or costs for construction purposes.[120] Despite the fact that the length of time SCE holds on to specific

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[119] Standard Practice U-16, p.3-7.

[120] See Standard Practice U-16, p. 3-4.

customer deposits may be limited, those deposits can be used to offset cash requirements. For this reason, we will not exclude any of the weighted average customer deposit balance from the amount used to offset rate base.

The weighted average balances of customer deposits from 1999 to 2004 are as follows:[121]

1999	$97,027,000
2000	$89,218,000
2001	$104,332,000
2002	$135,703,000
2003	$148,325,000
2004	$159,650,000

The recorded data shows a generally increasing trend from 1999 to 2004. We note that both SCE and Aglet estimate customer deposit balances for 2006 that are below that recorded for 2003 and 2004. Based on our discussion above, it would be reasonable to instead base the adopted customer deposit balance to be deducted from rate base on the 2004 recorded amount of $159,650,000.

19.9 Reserves for Worker's Compensation and Injuries and Damages

TURN recommends that the reserve for workers' compensation claims and the reserve for injuries and damages other than workers' compensation claims be included as offsets to rate base, thus reducing rate base by $142,790,000 ($109,968,000 for workers' compensation ands $32,822,000 for injuries and damages). TURN explains that these reserves constitute capital not

[121] See Exhibit 80, p.60 and Exhibit 409, p.1.

supplied by investors, as they are funds paid as expenses, through rates, in advance of when SCE makes payments to workers. Therefore, the reserves should be removed from rate base, consistent with the direction supplied by Standard Practice U-16, which allows for accounts held by SCE that do not earn interest to be counted as an offset to rate base.

TURN states that, if the Commission does not adopt TURN's recommendation, then to be consistent, the Commission should also recognize that these costs are largely not cash expenses for SCE, but are provisions to a reserve account on which ratepayers would be earning no return and therefore do not belong in the lead-lag study at all. TURN's alternative recommendation would increase lag days by 0.553 days and reduce rate base by about $8,395,000.[122]

SCE states that TURN wrongly assumes that SCE's total recorded reserve balance represents ratepayer contributions. Consistent with prior GRCs, SCE has requested annual provisions for workers' compensation that represents accruals set aside for anticipated future obligations. This annual provision accumulates in SCE's reserve for workers' compensation as a liability to the company, until such time as the payments are made. SCE states that, to the extent that actual liability payments exceed the authorized annual provisions accumulated to the workers' compensation reserve, additional accrual provisions above and beyond the authorized levels are recorded to the reserve at shareholder expense. SCE indicates that significant increases in workers' compensation liabilities have resulted in SCE making payments that have far

[122] *See*, Comparison Exhibit, p. 52.

outstripped the currently authorized levels.[123] For this reason, the recorded accumulated workers' compensation reserve represents amounts that have been funded by shareholders, not ratepayers, and SCE argues that TURN's recommendation to offset rate base should be rejected.

On the other hand, SCE agrees with TURN's alternative proposal to remove the injuries and damages and workers' compensation accruals from the lead-lag determination component of working cash. Under current accounting for workers' compensation accruals, SCE believes that ratepayers should not be required to pay for the timing lag between when shareholders bear the costs of funding the future obligations to when revenues are received. SCE states it will reduce the 2006 working cash request by $8,395,000 to account for this.

For the reasons discussed below, we will not adopt TURN's primary recommendation in this GRC.

19.10 Discussion

For liability accounts that are traditionally deducted from rate base, the ratemaking concept is clear. For instance, accrued vacation represents monies collected through operating expenses for future liabilities which the utility has available until payments to employees for vacation are made. In the GRC, the forecast of the amounts of accrued vacation to be recorded in the test year are deducted from the test year rate base. Similarly, customer deposits represent monies advanced by the customer as security for the payment of utility bills. The utility has use of those funds until refunds to customers are made.

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[123] SCE indicates that recorded accruals have exceeded authorized accruals by $111,000,000 more than the entire workers' compensation reserve since 1995. Also, for the period 1995 to 2002, the actual payments have been larger than the authorized accruals. (SCE, Transcript V. 21, pp. 2087-2088.)

Again, in the GRC, the forecast of the amounts to be recorded in the test year are appropriately deducted from the test year rate base.

The appropriate ratemaking for the workers' compensation and injuries and damages (other than workers' compensation) reserves is not as clear as that for accrued vacation or customer deposits. Whether ratepayers have provided the funds for these reserves is questionable. SCE explains the reserves for workers' compensation and claims as follows:

> The instructions of FERC Account 925 states that the utility shall "reserve accruals to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims." Based on these instructions and because the Company is self-insured for workers' compensation claims, the State of California requires that we reserve for all anticipated workers' compensation-related claims and contingent liabilities. This accounting methodology is also consistent with matching principle of GAAP, which requires that revenues be matched with expenses in the period incurred. The reserves established on behalf of the Claims Division are similar to the procedures used for the Workers' Compensation Division. In the Claims area, we establish reserves up to our self-insured limit of $2 million per incident.
>
> On a monthly basis, the reserve is credited for payments made on behalf of workers' compensation and other claim-related matters to medical providers, employees, third parties and for negotiated settlements. The total paid in any given month is determined by the actual payments recorded in various accounting functions, which are totaled and offset to an insurance reserve account and debited to function 0162 – Provision for Injuries and Damages Reserve. For example, if an employee suffers from an ankle sprain that requires

> therapy, the actual cost of therapy is debited on a monthly basis to function 0162 of Account 925.
>
> The overall increase in reserves is associated with several factors: (1) the audit by Self-Insurance Plans in 2001 for injuries reported between 1996 and 1998; (2) the increase in medical reserves for all life time medical awards, estimated for the life time of injured workers in accordance with the new life expectancy table; (3) adjustments in reserves in compliance with the increase of indemnity benefits passed by the legislature in AB 749; and (4) the quarterly certification requirement as a result of Sarbanes-Oxley Act 2002.
>
> Reforms such as AB 749 will continue to increase our reserves and claim payments. However, we are hopeful that other reforms, such as AB 227, SB 228, SB 899, will reduce costs.[124]

The reserve is a summation of recorded reserve expenses less actual payments. The reserve expense is reflected in rates on a forecasted basis.

Regarding the authorized and recorded accruals SCE stated:

> The factual record developed during the evidentiary hearings established that there is no nexus between the recorded accruals and any request made in this general rate case. Based upon authorized reserve accruals, instead of recorded, the workers compensation reserve would be more than eliminated.[125]

In response to SCE's claim, TURN argues:

> A cardinal principle of ratemaking is that any cost included in rates should be deemed to be funded by ratepayers, without a microscopic examination of

[124] SCE, Exhibit 71, pp. 60-61

[125] SCE, Opening Brief, p. 194.

> specific accounts. The purpose of a rate case is not to set a budget for specific accounts but to establish an overall utility revenue requirement that gives the utility management, using reasonable discretion, an opportunity to earn its authorized rate of return. Therefore, the Commission should not look at so-called "authorized reserve accrual" to account 925 when evaluating the source of the reserve for injuries an damages in isolation from other ratepayer dollars received by the utility.

The issue appears to be whether ratepayers or shareholders have funded the recorded reserve expense. TURN's argues that ratepayers, in principle, are responsible for the reserve expense. Therefore, it should be assumed that ratepayers have funded the recorded reserve expenses. SCE, on the other hand, argues that recorded reserve expenses have far exceeded authorized expenses and provides some reasons for the overall increases in reserves. Therefore, shareholders have funded the recorded reserve expenses.

In principle, if a cost is assumed to be in rates, the recorded amount should be assumed to be paid by ratepayers. For instance for accrued vacation, since vacation is an element of costs included in rates, the recorded deferred amount is used to reduce rate base. Whether authorized vacation, or the associated labor cost, is more or less than the recorded amount is not an issue. However, there appears to be a difference between the accrued vacation balance and the workers' compensation reserve. The recorded accrued vacation balance is just that -- a recorded amount that is based on actual vacation earned and taken. On the other hand, the recorded workers compensation reserve appears to be based on the accumulation of recorded reserve expenses which may include recorded payments for that year but which will likely also include a calculation of certain obligation for a time period beyond that specific recorded

year. Calculations of future obligations can be a significant part of the reserve expense for any particular year.[126]

Assuming ratepayers fund a forecast of workers' compensation payments for a specific year plus certain future obligations beyond that year, we can make some comparisons with the ratemaking for other reserves such as that for vacation accruals. Workers' compensation payments for a specific year are similar to the deferred vacation accrual. One could reasonably argue that ratepayers have funded any recorded workers' compensation payments. Just because the amount actually paid does not directly relate to what was assumed in the reserve expense does not matter. In principle, the ratepayers funded the recorded payment. However, in the case of the future obligations beyond the specific year, the recorded payments will not be known until they are actually made. Again those actually incurred expenses would be assumed to be paid by ratepayers. In the meantime the calculation of those future obligations may differ from what is ultimately paid, if assumptions such as level of indemnity benefits differ from what is used when the actual payment is made. It is reasonable to assume that, ratepayers are paying for those forecasted costs that are used to develop rates. However, it is not clear that, if a calculation of future obligations used in developing the authorized reserve expense differs from that is used in calculating the recorded expense, the ratepayers have necessarily funded the resultant change in the reserve. Therefore, we decline to adopt

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[126] For example the recorded workers' compensation reserve expense for 2003 was close to $60,000,000 while the recorded payments were approximately $20,000,000. *See* Exhibit 356, p. 50

TURN's primary recommendation, which assumes ratepayers have funded the entire reserve just because the authorized reserve expense is included in rates.

For this GRC, in order to determine the ratepayer or shareholder funding responsibility for the reserves, we will consider the relevant reserve accruals. In this case, the evidence indicates that recorded workers' compensation reserve accruals have exceeded authorized accruals by approximately $111,000,000 since 1995. Also, for the period 1995 to 2002, the actual payments have been larger than the authorized accruals. Lacking any better evidence, it is reasonable to assume that shareholders, not ratepayers, have funded the workers compensation reserve. For injuries and damages other than workers' compensation, there is no evidence showing that shareholders have funded that reserve, and we will adopt TURN's recommendation. In declining to adopt TURN's primary recommendation for workers' compensation, we believe that the weight of the evidence favors SCE, but it is not overwhelming. In its next GRC, SCE would do well to provide a clear record on this issue. Finally, for workers' compensation, we will adopt TURN's alternative proposal to remove the related accrual from the lead-lag determination component of working cash.

19.11 Working Cash – Other Accounts Receivable – Uncollectibles Other than Claims

TURN recommends the inclusion of uncollectible reserves for other accounts receivable aside from claims, which would result in a $2,600,000 reduction to working cash. SCE indicates that it has not requested recovery of the "atypical" uncollectible accounts receivable for non-claims in its test year request and has not included it in its lead-lag study. Since this particular uncollectible amount is not funded in rates, it should not be included as an offset to working cash. We will not adopt TURN's recommendation to do so.

20. Other Differences

The Joint Comparison Exhibit lists a number of differences related to other issues. This includes differences in uncollectible accounts, administrative expenses transferred, pensions and benefits, franchise requirements, miscellaneous general expenses, ad valorem taxes, payroll taxes, income taxes, plant in service and plant held for future use, working cash, accumulated depreciation and accumulated deferred taxes other than CIAC. Those specified differences are not caused by differences in methodologies but are caused instead by differences in the inputs used to calculate the costs. Depending on the resolution of the other issues, the differences related to the other issues are reconciled by the Results of Operations model, and are reflected in the various Appendix C Tables.

21. Post-test year Ratemaking

21.1 SCE's Request

SCE proposes to extend its current Post-test year Ratemaking (PTYR) mechanism that was adopted in its 2003 GRC. Its proposal has the following features:

- An annual advice letter providing notice of the revenue requirement change for the following year;
- O&M escalation using the GRC escalation rate methodology, updated at the time of the advice letter filing;
- Capital-related cost increases based on SCE's forecast of post-test year capital expenditures, updated for changes in SCE's authorized cost of capital;
- An annual revenue adjustment to reflect the number of nuclear refueling outages at SONGS and cost per refueling outage as adopted in this proceeding and updated for escalation;

- A revenue adjustment if necessary to reflect major maintenance outages at Four Corners Generating Station; and
- A mechanism to address major exogenous changes in SCE's costs.

In authorizing post-test year ratemaking for 2004 and 2005, the Commission imposed a requirement that if SCE's revenue requirement increase were to exceed $150,000,000 in either year, SCE would be required to submit an application for that year, rather than an advice letter. SCE asserts that unlike its previous GRC application, this application contains testimony supporting its proposed capital expenditures through 2008, not just through the test year. Because of this, SCE states that there is no substantial component of SCE's post-test year ratemaking mechanism that is not addressed by testimony in this application, and the Commission should not require SCE to submit a second application in 2006 or 2007 to reapprove its proposed mechanism.

Based on its proposed mechanism and test year 2006 estimates, SCE estimates a 2007 revenue requirement increase of $108,485,000 over its proposed 2006 level and a 2008 revenue requirement increase of $113,015,000 over its estimated 2007 level.

SCE argues that adoption of its proposal is necessary for it to be able to cover its costs of doing business in 2007 and 2008. The proposed increases will cover cost increases caused by increased capital spending, including the need to replace aging infrastructure facilities, and the impact of price inflation on operating expenses.

21.2 DRA's Recommendation

DRA does not oppose a mechanism that provides SCE the opportunity to earn its authorized rate of return for its GRC related operations

during the years 2007-2009. However, DRA does not agree with SCE's PTYR proposal and recommends the following:

- A Consumer Price Index (CPI) indexing method to determine SCE's PTYR revenue requirements between general rate cases. This method will allow SCE's rates to increase with inflation, and encourage SCE to be efficient, productive, and innovative.
- As an alternative to its proposed CPI indexing method DRA recommends that SCE's PTYR capital additions be based upon historical attrition rates rather than estimates that are based on SCE's preliminary planning.
- DRA recommends one additional attrition year in 2009 be incorporated into the PTYR cycle.

DRA states that its proposed CPI indexing method is predicated on the following:

- The Commission's position is that attrition rate changes are not an entitlement and some utilities have been denied attrition rate increases recently.
- Using a properly developed CPI indexing method between rate cases, give utilities an incentive to minimize their costs.
- The Commission has adopted indexing methods for utilities in the past including:
  - Telephone utilities using the New Regulatory Framework authorized in D.89-10-031;
  - Class C and D water utilities in D.92-03-093;
  - PG&E in D.04-05-055; and,
  - SoCalGas and SDG&E in D.05-03-023.
- A CPI indexing method encourages efficiency, cost savings, and innovation.

- SCE's method discourages efficiency, cost savings, and innovation.
- DRA's CPI indexing method allows for a balanced and reasonable method to calculate base margin revenue requirement during the PTYR period.
- DRA's CPI indexing method is easy to use.

DRA's recommendation that one additional year in 2009 be incorporated into the post-test year ratemaking cycle is based on a number of factors. First, inflation has been modest over the past 15 years. Second, a longer attrition period gives more time between the issuance of a decision and the filing of the next case. Third, extending the attrition period will provide the Commission with more data to use in determine SCE's future rates. Fourth, another year of attrition will give SCE another year free of the Commission's oversight. Fifth, utilities, because of the regulatory protections, no longer need general rate cases every three years. Finally, a four-year attrition period is consistent with the current longer regulatory cycle used by PG&E, SoCalGas, SDG&E, Southwest Gas, and most small utilities operating in California.

Based on its proposed CPI mechanism and test year 2006 estimates, DRA estimates a 2007 revenue requirement increase of $2,030,000 over its recommended 2006 revenue requirement level and a 2008 revenue requirement decrease of $9,825,000 to its estimated 2007 revenue requirement level.

As an alternative to DRA's primary recommendation to use a CPI indexing method to set SCE's Attrition rates, DRA recommends annual increases that do not exceed the level based on the historical attrition rate setting method. This involves: (1) increasing operational expenses for inflation and (2) increasing capital-related costs based on recent historical plant additions.

Regarding capital related costs, DRA states:

> The capital related portion of SCE's revenue requirement estimate for the post-test year is based in part on the accumulated plant balances estimated for 2003 and annual plant additions for each of the years 2004 and 2005. Capital related costs such as net return on rate base, income taxes, property taxes and depreciation expense are directly related to the accumulated plant balance for that year. ORA does not dispute the use of the estimated accumulated plant balance at the end of 2006 as the starting point to estimate plant balances for both 2007 and 2008. ORA used its estimate of the end of year 2006 plant balances for this purpose. However, SCE's estimates of plant additions for 2007 and 2008 are budget-based and are not based on SCE's historic capital additions consistent with traditional attrition relief. ORA is not able to conduct a detailed analyses of SCE's post-test year plant additions. For these reasons, ORA based its estimates of plant additions primarily on recent historic recorded plant additions, which is consistent with the historical attrition method used by this Commission.[127]

Based on its alternative methodology and test year 2006 estimates, DRA estimates a 2007 revenue requirement increase of $97,840,000 over its recommended 2006 revenue requirement level and a 2008 revenue requirement increase of $12,080,000 over its estimated 2007 revenue requirement level.

21.3 Aglet's Recommendation

Aglet also does not agree with SCE's PTYR proposal. Consistent with DRA's primary recommendation, Aglet recommends a CPI indexing method to adjust SCE's base rate revenue requirements between GRCs. Aglet makes the following points in supporting the use of a CPI index:

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[127] DRA, Bumgardner, Ex. 202, pp. 16-12.

- Simplicity - Calculation of CPI-based revenue requirements is much easier than SCE's calculations.
- Comprehension by Consumers - The CPI is a measure of inflation that is widely recognized by consumers. Small customers identify the connection between retail price changes and the CPI, and large customers have seen the CPI used as a price index in long-term contracts. Reliance on the CPI will help customers understand the reasons behind rate changes between GRC, leading to increased consumer confidence in Commission regulation.
- Verification - The CPI is objective and easily verified. The utilities and Commission staff subscribe to Global Insight publications, which include CPI forecasts. These attributes lead to public trust in the relevant calculations, and use without controversy.
- Revision - The CPI is not generally subject to revision. Reliance on an October forecast of the next year's CPI introduces a modest amount of uncertainty, but that risk is no different from the uncertainty the Commission accepts in forecasting test year revenue requirements for utilities generally.
- Stability - The CPI is generally less volatile than utility price indices. SCE has reported that volatility is a serious problem with industry-specific indices because it destabilizes utility rates and earnings, which could lead to an increase in cost of capital.
- Bias - Aglet is aware of no record evidence that shows long-term CPI bias compared to utility price indices.

Aglet asserts that, taken as a whole, the evidence shows that for ratemaking purposes the CPI is superior to utility price indices as a measure of price escalation.

With regard to SCE's post-test year capital budgets, Aglet notes that only $40,000,000 of the capital costs (compared to more than $1.8 billion in capital

additions for each of the years 2007 and 2008) are supported by cost-effectiveness analysis. In agreeing with DRA's argument that budget-based ratemaking in 2007 and 2008 may encourage excessive capitalization of plant additions without sufficient safeguards to protect ratepayer interest as to the need or reasonableness of the plant additions, Aglet states:

> The current and proposed post-test year ratemaking schemes give SCE an incentive to overestimate its capital forecasts, and later reduce revenue requirements so that virtually all recorded expenditures are recovered in rates. This outcome is very close to recorded cost ratemaking for SCE. Due in part to the scope of general rate cases, no other party has the resources to test the reasonableness of actual capital costs. There is no showing in this proceeding of the reasonableness of SCE's 2004 and 2005 capital spending, and I expect there will be no showing in the next general rate case of the reasonableness of SCE's 2007 and 2008 spending. These are fundamental flaws to budget-based ratemaking.[128]

21.4 TURN's Recommendation

TURN recommends that the Commission should adopt a CPI-based escalation of the entire base revenue requirement as recommended by Aglet and the DRA. Regarding SCE's request to continue a "budget based" attrition mechanism, as it relates to capital related revenue requirement for 2007 and 2008, TURN observes that:

> The primary responsibility of the ORA and intervenors has traditionally been to review the prudency and reasonableness of historical capital additions and the reasonableness of the test year forecast. Adding to this the need to review the reasonableness of capital budget

[128] Aglet, Exhibit 407, p. 31.

> forecasts two or three attrition years results in an unmanageable task. There is no disincentive for the utility to provide realistic capital forecasts, as it has every incentive to over inflate expected costs and no incentive for cost control.[129]

21.5 SCE's Rebuttal Testimony

In response to the DRA, Aglet and TURN PTYR proposals, SCE makes the following arguments:

- The CPI is not an accurate escalation rate to use for SCE's revenue requirement with respect to expense or capital because it ignores the realities of SCE's need for adequate revenues to support its capital investments. The CPI is a measure of price inflation in the goods and services purchased by consumers, not the goods and services purchased by electric utilities.
- If DRA had used the model for the CPI estimate as it did for the hybrid-attrition forecast, it would have accurately forecast its three-year GRC revenue requirements for the entire GRC cycle. By taking this shortcut, DRA did not recognize that SCE would be required to cut an additional $706 million in capital expenditures in the test year—beyond the adjustments already recommended by DRA in its testimony. This additional reduction in capital expenditures occurs because DRA did not recognize a forecast year-end 2006 Construction Work in Progress (CWIP) balance of $742 million.
- The DRA proposed alternative for cost recovery in 2007 and 2008 is not equivalent to the Attrition formulas adopted by this Commission in SCE's general rate cases in the 1980s and early 1990s. When the Commission adopted Attrition ratemaking for

[129] TURN, Opening Brief, p. 174.

SCE in previous GRC, the formula was a combination of the average of SCE recorded capital additions, plus the forecast of large capital projects (usually generation), which comprised the capital portion of the attrition year revenue requirement (adjusted for customer growth). In the attrition methodology, large capital projects were forecast on a work order or project-specific basis and the balance of the capital forecast was the product of a historic average of capital additions. In those earlier years, the large projects were usually in the areas of generation. However, given the capital needs of SCE's transmission and distribution system, initiatives such as the Infrastructure Replacement program are similar to those large generation projects that were separately forecast in the attrition formula when the Commission approved SCE's general rate cases in the 1980s and early 1990s.

- Regarding the DRA and Aglet claim that the CPI-indexing methodology is a simpler approach than SCE's PTYR proposal, the Commission has previously rejected this argument in SCE's 2003 GRC decision, D.04-07-022, "This [CPI] 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."
- The CPI is projected to increase less rapidly than SCE's O&M escalation indexes over the post-test year period. Thus, the CPI is an inadequate escalator for SCE's O&M expenses.
- Many of SCE's capital assets have long lives and an escalation rate for capital related costs must account for more than contemporaneous changes in prices. The CPI which is based on current information about prices cannot do this. Therefore, reliance on the CPI

to project increases in SCE's capital costs should also be rejected.

- DRA and Aglet's reliance on recent settlements with PG&E and SDG&E cases to support their CPI methodology should be rejected. It is well established that settlements in regulatory proceedings are compromises between the parties involved, the terms of which are not precedential.
- The Capital Additions Adjustment Mechanism (CAAM) protects SCE customers by ensuring that authorized revenue requirements are adjusted to recover only the costs of capital investments that are actually made and placed into service. If SCE does not make investments equal to or greater than the authorized level, SCE will return the excess revenue requirement to ratepayers. The reasonableness of SCE's capital investments, scope changes or capital addition substitutions can be reviewed by the Commission in any subsequent general rate cases, just as they have in the past.
- In opposing SCE's PTYR proposal, the DRA, Aglet and TURN implicitly argue that the Commission should reverse its policy decision that authorized funding for the Infrastructure Replacement program. In the 2003 GRC decision, D.04-07-022, the Commission recognized the importance of this program and made a policy decision to authorize increased capital expenditures to support SCE's investments to meet customer growth, load growth and to increase our level of investment in the infrastructure replacement program.
- SCE's proposed capital expenditures, when compared with the level proposed by DRA, will result in greater overall economic activity in Southern California, even after absorbing the cost of the associated revenue requirement. These economic benefits are in addition to the direct benefits from

maintaining SCE's system that will be realized by SCE's customers if SCE's proposed capital expenditures are adopted.

- DRA's proposal to extend the attrition mechanism through 2009 lacks merit and should be rejected. DRA's proposal would require the Commission to set rates on recorded data that is over five years old, an approach the Commission has rejected. Also, there is no evidence in this GRC of SCE's capital forecast in 2009. In addition, DRA's reliance on prior settlements as authority for its proposal to extend the attrition mechanism should be rejected because settlements are not precedential.
- The DRA, Aglet and TURN proposals would reverse a policy decision the Commission made only one year ago to support SCE's capital investment program. The adoption of any of these proposals will also lead to the inevitable degradation of the electric system reliability. Therefore, SCE respectfully requests that the Commission resist the temptation of issuing a compromise decision between the DRA, Aglet or TURN proposals and SCE's PTYR proposal.

21.6 Discussion

Rates for post-test year 2007 and 2008 could be determined in the same manner as for test year 2006. Estimates of sales, revenues, operating expenses, capital additions, and capital related revenue requirement can be determined for each of the post-test years 2007 and 2008 similar to what is done for test year 2006. However, this would be time consuming and complicated in that it would expand the scope and analysis of many aspects of the GRC by a factor of three (three test years versus one test year). Rather than subjecting post-test years to the same scrutiny as test years, the Commission has adopted "attrition" and subsequently "post-test year" (PTY) methodologies as substitute measures for determining rates for the time period between test years.

The attrition methodologies adopted in D.85-12-076 and used during much of the 1980's and 1990's, among other things, determined attrition year revenue requirements by escalating operation and maintenance expenses by forecasted inflation factors[130] and determining capital related costs based on forecasted attrition year plant additions. SCE essentially followed this procedure in determining its PTY revenue requirements, although it used a budget based approach for forecasting PTY plant additions. DRA also used this methodology in its alternate PTY recommendation. DRA used a four-year average of escalated historic and forecasted plant additions (2004 – 2006) to estimate plant additions for 2007 and 2008. There is merit to this type of analysis because the increase in revenue requirements can directly be tied to the principal factors that cause the operational attrition – inflation as it relates to expenses and annual plant additions. For capital-related costs, the reasonableness of the increases relates directly to the reasonableness of the adopted plant additions.

A CPI methodology, DRA's principal recommendation, has been recently adopted by the Commission in determining attrition for PG&E and SDG&E.[131] Various forms of indexing have also been used in other proceedings such as performance based ratemaking (PBR) for energy utilities and the new regulatory framework (NRF) for telecommunication utilities. Indices can be applied to rates or to revenue requirement.

In one respect, DRA's CPI proposal is similar to previous attrition methodologies. That is it could be assumed its proposal escalates operation and

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[130] In D.85-12-076, expenses related to customer growth were assumed to be offset by productivity.

[131] *See* D.04-05-055 and D.05-03-023.

maintenance expenses by a forecasted inflation factor, that being the CPI rather than specific O&M escalation factors. However, it would then follow that DRA's proposal also escalates capital related costs by the CPI. This is in contrast to previous attrition methodologies where capital related costs are calculated based on the effect of forecasted plant additions being added to the test year base. By the CPI method, the escalated capital related costs do not specifically take into consideration the magnitude of post-test year plant additions, the increases to depreciation expense and the effects of accumulated depreciation and deferred tax reserves. A determination of the reasonableness of the results is therefore more complicated. A test could be whether the results provided reasonable capital related costs based on a reasonable level of plant in service or plant additions for each of the post-test years. For instance, in D.97-07-054, the Commission determined that an indexing methodology applied to capital related costs was not appropriate for SoCalGas because, in fact, annual depreciation accruals exceeded annual plant additions and rate base was therefore declining. Certain capital related costs, such as return on rate base, should therefore have been forecasted to decline rather increase as was reflected in the proposed indexing methodology.[132] While a modified indexing methodology was ultimately adopted, the Commission did state:

> "We would prefer to adopt a method to take rate base changes into account outside of the indexing formula. A methodology such as a direct revenue offset or adjustment of the benchmark rate of return could accomplish this. However, no party has proposed such

[132] In its performance based ratemaking application, A.95-06-002, SoCalGas proposed to increase rates by price inflation less a productivity factor.

> a method, and we must rely upon the indexing methodology, in which rate base factors are effectively translated into productivity. SoCal estimates in its comments on the Proposed Decision (p. 4) that the impact of the TURN/DGS formula may result in an effective productivity factor as high as 2.9%, which is 1.4 % above the 1.5% final stretch "X" factor. This suggests that it may be possible to translate directly the TURN/DGS formula into a straight productivity figure and thus roughly reconcile the TURN/DGS concept with the indexing methodologies adopted in other PBRs."[133]

In that proceeding, the Commission considered the effect of an indexing methodology in light of evidence that showed that rate base would likely decline. Because the indexing methodology, as proposed, would likely have resulted in an excessive rate increase, it was rejected and modified.

Under different circumstances, indexing may well be appropriate. In the last PG&E and SDG&E general rate proceedings, there were no claims by any of the parties that a proposed CPI indexing methodology would result in excessive or inadequate rates to cover capital related or other costs. Applicants, as well other interested parties, were apparently satisfied that, in those cases, the CPI methodology would provide reasonable results. The Commission did not find otherwise and adopted a CPI methodology for PG&E and for SDG&E. We are therefore open to the use of CPI indexing to set rates for the post-test year period. However, as in A.95-06-002, we must consider the views of dissenting parties and ensure the reasonableness what is adopted. In this case, SCE objects to the use of the CPI methodology and has provided information that casts doubt

[133] D.97-07-054, *mimeo.*, p. 37.

on the reasonableness of its use for determining post-test year revenue requirements.

The CPI methodology proposed by DRA and endorsed by Aglet and TURN increases authorized revenue requirement (essentially expenses and the capital related revenue requirement) by the percentage increase in the CPI. That revenue requirement increase is then reduced by increased revenues from forecasted increased sales. The net amount represents the change in revenues that SCE would see and would have to cover increases caused by expense inflation and incremental costs to serve new customers and increased load. The revenue increases calculated by increasing the authorized revenue requirement by the CPI increases for 2007 and 2008 are offset by increases in the revenues generated by increased sales to the extent that there is essentially no effect on the rates charged to ratepayers under DRA's primary PYTR proposal.

As discussed above, CPI increases, or inflation increases in general, are not linked to the capital expenditure cost increases that the utility incurs but instead relate to capital related costs such as return on rate base, income taxes and depreciation, which are the items that are directly reflected in the revenue requirement. For that reason, a CPI increase may not fairly represent reasonable overall cost increases to the utility. There has to be some kind of check for reasonableness. The check is usually some type of calculation of the revenue increases generated using accepted ratemaking principles and specific assumptions related to those principles. In this case, SCE calculated the capital expenditures associated with DRA's proposal and prioritized projects that could be done within that funding level. The major point of SCE's rebuttal testimony is that DRA's proposed revenues do not support a capital expenditure level that will enable it to provide safe and reliable service.

The question of whether simplified methods to basic ratemaking principles are worth pursuing can only be answered on a case-by-case basis. In this case, because of the effect on SCE's future capital expenditure levels, we will not use the CPI methodology proposed by DRA. The plant additions implicit in DRA's PTY CPI proposal are significantly less than what we, by this decision, are adopting for SCE for test year 2006. Such reductions are counter to our commitment, as discussed previously, to facilitate the replacement of SCE's transmission and distribution infrastructure in a timely and efficient manner.

We note that a CPI methodology could be constructed in other ways depending on what the CPI increase is intended to represent. It could be argued that the CPI should represent the effect on ratepayers. That is, if the CPI is projected to increase by 2% in a year, the utility rates would increase 2% for that year. That would be simple to implement. Also, the link between increases in the CPI and increases in rates should be fairly understandable to utility customers. In fact, in the customer/CPUC correspondence generated by this GRC, a number of customers complain that the proposed increases exceed the CPI changes or cost of living increases in general. However the difference between escalating rates by the CPI increase and escalating the revenue requirement by the CPI, as recommended by DRA, is large.

For example, the effect of escalating rates by the CPI can be approximated by first taking the increase in revenue requirement calculated by applying the CPI increase to the last authorized revenue requirement. That would represent the increase to the existing customers at existing sales levels. On top of this, additional sales related to increased usage and new customers

would be coming in under this CPI escalated rate and the utility would capture the increased revenues.[134] Using DRA's recommended 2006 revenue requirement of $3,592,407,000[135] and CPI increases of 1.90% for 2007 and 2.10% for 2008 results in increases of $68,256,000 in 2007 and $76,947,000 in 2008. In its PTYR calculations, DRA used revenue growth due to sales increases of $65,382,000 for 2007 and $85,752,000 for 2008. Adding these elements results in revenue increases of $133,638,000 in 2007 and $162,699,000 in 2008, for a total of $296,337,000. The total is larger than that requested by SCE in its application showing ($159,447,000 in 2007 and $121,522,000 in 2008 for a total of $281,969,000).[136] In this case, a CPI methodology would result in providing SCE with more money than what it though it needed. This is not a recommendation by any party in this proceeding. It merely demonstrates that while attractive, simplified methodologies may not be appropriate and may not produce reasonable results.

In rejecting the CPI methodology, we must now determine appropriate levels of plant additions for 2007 and 2008. For calculating the capital related costs, SCE has included its proposed capital budget for 2007 and 2008. However, no party other than SCE provided or analyzed detailed post test year plant addition budget forecasts in determining post test year rate increases. We cannot fault other parties for not recommending detailed post test year capital budgets. Analyzing such budgets for two additional years imposes a

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[134] For this hypothetical example, since rates are being indexed, it assumed there is no revenue balancing account.

[135] Exhibit 899, p. 4.

[136] This analysis excludes the effects of the one-time PBOP refund in 2006.

significant burden on resources. When the current rate case plan was adopted, post test year capital revenue requirements were generally determined using simplified methods for determining post test year plant additions. Averages of recorded/estimated plant additions or plant additions per customer were typically used. We note that in its alternate recommendation, DRA bases 2007 and 2008 plant additions on a five year average of historic and estimated plant additions for the 2002 through 2006 time period, in 2003 constant dollars.

SCE's capital budget for 2006 has been scrutinized in this rate case and certain reductions to that budget are reflected in our decision today. That, along with the fact that no other party performed a detailed review of SCE's post-test year budget for the years 2007 and 2008, leads us to conclude that it would not be appropriate to base plant additions on SCE's budgets for those years. DRA's alternate recommendation for 2007 and 2008, in constant dollars, is less than its estimate for 2006 plant additions. Also, our decision today adopts 2006 plant additions greater than that recommended by DRA. The use of DRA's alternate recommendation for post-test year plant additions would not be consistent with our commitment to facilitate SCE's infrastructure replacement and meet its other capital needs.

Rather than choosing between SCE's budget and DRA's estimate, we will instead use the plant addition level that has been reviewed and adopted for 2006, escalated for inflation to 2007 and 2008 levels.[137] While not quite as ambitious as proposed by SCE, adopted levels for 2007 and 2008 will allow SCE

[137] Adopted gross additions for 2006 amount to $1,622,147,000. The escalated amounts are $1,643,050,000 for post-test year 2007 and $1,668,348,000 for post-test year 2008.

to continue its infrastructure replacement at the adopted 2006 level, which is substantial.

For capital escalation in general, SCE assumed a 3% per year rate for both 2007 and 2008. That rate for those years was not addressed by any other parties, since it was not used by any other parties. DRA's forecast of the CPI increase for its post test year recommendation was 1.9% for 2007 and 2.1% for 2008. SCE objected to the use of the CPI as it was applied in DRA's primary PTYR recommendation. If 2006 plant additions are to be escalated to post test year levels, Aglet recommends the use of the CPI.[138] For the October 5, 2005 update testimony, SCE provided escalation factors for labor and non-labor expense. Labor expense is expected to increase by 3.60% in 2006 and 3.35% in 2008. Non-labor expenses for transmission are expected to increase by 1.49% in 2007 and 1.35% in 2008. Distribution non-labor expenses are expected to increase by .93% in 2007 and 1.11% in 2008. The update testimony did not address the CPI or capital escalation. Based on the above stated evidence in this proceeding, it is reasonable to use a capital escalation rate of 2.5% per year to escalate 2006 plant additions to post test year 2007 and 2008 levels.

In its alternate recommendation, DRA recommends that O&M inflation be based on its recommendations for labor and non labor inflation for the 2004 – 2006 period. While benefit escalation is not discussed in escalation testimony, DRA concurred with SCE's labor and non-labor escalation estimates. We will adopt SCE's methodology for O&M expense escalation, including that for benefits. We will also adopt SCE's proposed annual advice letter procedure

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[138] See Comments of Aglet Consumer Alliance on Proposed Decision of ALJ Fukutome, p. 8.

for implementing post-test year rate changes and the proposed mechanism to address major exogenous changes in SCE's costs.[139] Appendix D illustrates the calculation of the post-test year requirements using the methodology adopted by this decision.

DRA requests the Commission extend the rate case cycle associated with SCE's test year request to four years by including the additional post-test year 2009. SCE opposes the request. We will not extend the GRC cycle as requested by DRA. It is contrary to the current rate case plan that allows major energy utilities the opportunity to file GRC applications every three years. We would certainly consider the extension if SCE were in agreement. However, since SCE opposes the extension, changes to the length of the GRC cycle should be addressed through modification of the rate case plan, where the issues regarding the proper length of the cycle can be addressed by all affected parties and where the resultant decision could be applied fairly and consistently among the parties.

22. Performance Incentives for SONGS

The Commission sets both SCE's and SDG&E's revenue requirement for SONGS on a forecast basis. Under the operating agreement, SCE bills SDG&E a proportionate share of actual costs, regardless of the Commission's adopted forecast of these costs. Thus, SCE shareholders are at risk/reward for any difference between the Commission-adopted forecast for SCE's share of the plant costs and SCE's share of the actual costs, and SDG&E shareholders are at

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[139] Earlier in this decision we adopted SCE's proposed annual revenue adjustment to reflect the number of nuclear refueling outages at SONGS and rejected SCE's proposal for a similar adjustment mechanism at Four Corners.

risk/reward for any difference between the Commission-adopted forecast for SDG&E's share of the plant costs and SDG&E's share of the actual costs.

SDG&E now proposes a new ratemaking mechanism with respect to the recovery of SONGS costs by SCE from its customers, which SDG&E refers to as the CCIM. The intent of the proposed mechanism is to give SCE a greater incentive to manage effectively the capital and O&M for SONGS. SDG&E states that the record shows that SCE managed these costs much more effectively when it was subject to the ICIP incentive mechanism than in periods when it has been subject to traditional ratemaking. SDG&E is proposing that its recovery of SONGS costs billed to it by SCE be placed on a recorded basis rather than the traditional forecast basis. If SCE reduces the total costs of operating SONGS under the incentive of CCIM, its billings to SDG&E will decline proportionately, and the SDG&E's full share of the savings will be passed through on a recorded basis to SDG&E's customers. SDG&E argues that under the CCIM, both SCE's customers and SDG&E's customers would benefit from improved cost control and greater plant output as a result of an incentive mechanism.

SDG&E states that its preferred choice is to sell its ownership interest in SONGS to SCE and enter into a purchased power agreement (PPA) with SCE for the same amount of capacity that SDG&E currently owns in the plant. SDG&E presented this approach in SCE's A.04-02-026 for authorization to replace the SONGS Units 2 & 3 Steam Generators. It has not done so in this proceeding and, thus, is not here at issue. SDG&E states that if the Commission concludes in the steam generator proceeding that the buyout/PPA option is the best alternative, the SDG&E's CCIM proposed in this proceeding will not be required. SDG&E states that the buyout/PPA has its own incentive provisions

that will serve to keep SCE's SONGS costs in check to the benefit of both SCE's customers and customers served by SDG&E.

22.1 The Need for Incentive Ratemaking for SONGS

SDG&E indicates that it is extremely disturbed with SCE's historic inability, as the Operating Agent under the SONGS Operating Agreement, to manage SONGS 2 & 3 costs, as demonstrated over time by the fact that SCE routinely spends considerably more on both O&M and capital related costs than it forecasts. SDG&E further states that this history of substantial cost increases over forecasts is in marked contrast to the cost reductions that SCE was able to achieve during the Incremental Cost Incentive Pricing (ICIP) period of 1996 through 2003. In this proceeding SDG&E introduced a benchmarking study of SONGS performance during Pre-ICIP, ICIP and Post-ICIP years as well as against other nuclear facilities in the United States. This benchmarking study is intended to show that SCE can do considerably better in its efforts to manage SONGS costs when provided with the right incentives.

SDG&E states that as a co-owner of SONGS, SDG&E has come to realize that SCE's projections of the costs for SONGS -- capital, operation and maintenance, administrative and general, or any other cost – cannot be trusted, whether on a "next year" budget basis, a general rate case test year basis or on a forecast basis over a five year period of cost forecast presented to the Board of Review (BOR), which is the governing committed for SONGS under the Operating Agreement. It is SDG&E's position that SCE has not been able to control SONGS costs other than during those years when the ICIP was in place. In its testimony, SDG&E presented information showing that, during the Pre-ICIP years, recorded capital additions were 571% higher than preliminary budget estimates provided at BOR meetings. For the Post-ICIP years, recorded

and GRC forecasted additions are 130% higher than that provided in prior BOR meetings. However, during the ICIP years, there was a 46% decrease in the recorded capital expenditures when compared to the preliminary BOR budgets.

Regarding SCE's rebuttal which presented an alternate analysis that derived a variance as a percent of forecasted capital expenditures of 25%, SDG&E notes SCE's acknowledgement that the correct calculation was 27% and if the years were disaggregated by Pre-ICIP, ICIP, and Post- ICIP periods, the variance for the 1987 through 1995 period was 126%; for the 1996 through 2003 period was negative 53%; and the variance for the Post-ICIP period of 2004 was 288%. SDG&E points out that the different method of calculating a variance cannot obscure the purpose of SDG&E's analysis, which was to demonstrate that SCE's cost control performance during the ICIP years was substantially better than in non-ICIP years.

While stating that it is accurate that SCE generally adheres to the annual budgets that are presented to the BOR each January for approval, SDG&E states that the "budget" that SCE will manage toward for 2006 is not the one presented in this GRC. According to SDG&E, SCE will adopt its real 2006 budget next January, which may be very different from the cost estimates SCE presents to the Commission in this proceeding.

SDG&E acknowledges that some of the cost increases from the initial budget throughout this period of 1985 to 1995 and 2004 through 2005 resulted from events beyond SCE's control, such as the events of September 11, 2001, or events that occurred at other nuclear facilities, such as Davis Besse. However, SDG&E asserts that these substantial actual capital cost variances from the initial forecast of each year's capital budget are nonetheless reflective of SCE's inability to forecast capital costs at a SONGS because these costs are inherently uncertain

with a high likelihood of very large increases in capital cost exposure, including exposure from events beyond the control of the utility.

SDG&E indicates that this problem of actual costs exceeding forecasts and budgets by substantial amounts during periods when SCE is subject to traditional cost of service regulation is compounded for SDG&E, since it has no role to play in developing or influencing the budget. The Operating Agreement contemplates that SDG&E and the other minority owners have certain rights, *e.g.,* to approve budgets, which must be done on a unanimous basis. A dispute involving a budget requires the owners to continue to advance funds and proceed through an arbitration process. SDG&E points out that this arbitration process, including the standards that would govern an arbitrator's awards, allows SCE to continue operating under proposed budgets and requires an expensive, lengthy and risky process for SDG&E to contest SCE's expenditures after the fact. Moreover, as a minority owner, SDG&E states that it has no control over the actual expenditures made by SCE.

SDG&E provided a statistical comparison for the cost impact of ICIP by comparing the average of the annual benchmarking results as measured against a sample of 31 utilities that own and operate nuclear plants for the ICIP years to the average of the annual benchmarking results for a limited period of the non-ICIP historical years (1993-95 and 2004) and the three forecast years. SDG&E finds that in both periods in which SCE was not under ICIP it was an inferior cost performer at a 90% confidence level. For the 2005-2007 forecast period SCE's forecasted costs exceeded the model's prediction by 22.2% on average. During the ICIP years, in contrast, SCE's cost was a little below the model's prediction, although not significantly below it in the statistical sense. Statistical tests were conducted of the hypothesis that performance in the

ICIP years was equal or inferior to that in each of the two non-ICIP periods. According to SDG&E, these hypotheses were rejected in both cases, providing corroboration that the ICIP had its intended effect of causing SCE to be more efficient in its control over SONGS capital costs, which not inconsequentially also caused improved plant performance.

SDG&E concludes that SCE's cost control management track record during non-ICIP years provides compelling evidence that the Commission must adopt an effective PBR-type mechanism to encourage efficiency, like the PBR it approved for SCE in D.96-09-092. SCE states that such a new PBR mechanism applicable only to SONGS must include appropriate standards for service and safety and ensure fairness to ratepayers, employees and shareholders by balancing potentially conflicting interests.

22.2 SDG&E's Proposed CCIM

SDG&E recommends that the Commission adopt the CCIM for an eight year-period (2006-2013). The CCIM would incorporate the expenditures approved by the Commission in this proceeding and those expenditures approved by the Commission in subsequent SCE GRC.[140]

The proposed CCIM would be applicable only to SCE, since SCE is the SONGS Operating Agent under the Operating Agreement for SONGS. SDG&E would be subject to a two-way balancing account with its customers incurring only those SONGS costs billed by SCE to SDG&E plus SDG&E's direct SONGS related costs. Thus, SDG&E's shareholders will not benefit from any SONGS cost savings generated by SCE under the CCIM.

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[140] Major capital expenditures, such as the Steam Generator Replacement Application, would not be subject to the CCIM.

SCE's annual SONGS revenue requirement would reflect existing capital, O&M, property taxes, franchise fees, depreciation of existing capital, and rate of return on SONGS related rate base as of the end of 2005. New capital improvements in 2006 and thereafter would be expensed over a 12-month period commencing with the in-service date of the improvement, using Commission adopted forecasts of the costs for such improvements. Not included, nor subject to the CCIM, would be SCE's nuclear decommissioning costs and its nuclear fuel costs.

Under the proposed CCIM the annual revenue requirement for the years 2006 through 2013, adjusted for inflation, would be divided by the CPUC-adopted forecast capacity factor for the years 2006 through 2013 to determine a cents per kWh price that SCE will be allowed to charge its customers in each year for its share of the actual output that SONGS produces. Both the cost forecast and the capacity factor forecast would be addressed in a separate phase of this proceeding.

Embedded within the annual authorized revenue requirement would be SCE's authorized return on rate base. The proposed cost control incentive mechanism should also have a sharing feature based on SCE's actual earned rate of return for SONGS operations. Again, specific sharing mechanisms would be addressed in a separate phase.

SDG&E's annual SONGS revenue requirement would reflect existing capital, O&M, property taxes, franchise fees, depreciation of existing capital, rate of return on SONGS related rate base as of the end of 2005, nuclear decommissioning costs and its share of nuclear fuel costs. New capital improvements in 2006 and thereafter would be expensed over a 12-month period

commencing with the in-service date of the improvement, using Commission adopted forecasts of the costs for such improvements.

SDG&E would be subject to a two-way balancing account with its customers incurring only those SONGS costs billed by SCE to SDG&E plus SDG&E's direct SONGS related costs. Thus, SDG&E would initially charge its customers its 20% share of the SONGS revenue requirement established in this proceeding plus SDG&E's direct SONGS related costs. The two-way balancing account would track only SDG&E's actual SONGS costs billed by SCE against the revenue requirement adopted for SDG&E in this proceeding. The following year SDG&E would be authorized to recover the inflation adjusted revenue requirement for the next year adjusted to reflect any over-collection or under-collection from the previous year.

SDG&E makes the following observations:

- Because of SCE's cost over-runs associated with SONGS since the expiration of the ICIP in 2003, SDG&E desires to hold SCE accountable for this inability to control expenditures at SONGS. The proposed CCIM will accomplish this result. However, if SCE strives to control its SONGS related costs and is able to operate SONGS at a lower cost than incorporated into the rates from this proceeding, SDG&E believes a reward for this effort is justified. The proposed CCIM will provide SCE with this reward and furthermore benefit SCE's customers. It will also benefit SDG&E's customers because the lower SONGS costs and better plant performance will flow through to these customers as well as SCE's customers.
- It is anticipated that under the CCIM SCE's shareholders will benefit if it keeps its costs in check. But foremost, SCE's ratepayers will benefit as well when SCE is able to reduce its costs by sharing in any

additional earnings that SCE is able to achieve by reducing costs and improving plant performance. Conversely, if SCE is not able to control its costs and exceeds the CCIM cents per kWh price target approved by the Commission in this case, SCE's actual earned ROR for its SONGS operations will fall and SCE's shareholders will take share in the resulting economic penalty.

- Treating new non-major capital additions as expense under the proposed CCIM will provide greater incentives for good management by SCE of capital costs than under traditional ratemaking. Under traditional ratemaking, if the amount of capital additions exceed the Commission-allowed level for the rate case cycle, the utility shareholders do not recover return (and taxes) and depreciation on the excess capital spending for the term of the rate case cycle. However, as of the next rate case test year, the utility may then be able to earn a return on and of the remaining undepreciated amount of capital spending in excess of the previous allowed level. Under the proposed CCIM, there will be a greater incentive because if capital additions exceed the allowed level, SCE will never recover the excess in rates. Similarly, the benefit from managing capital spending below allowed levels will also be greater under CCIM than traditional ratemaking.
- The proposed earnings sharing mechanism also provides incentives for effectively managing expenses. The proposed earnings sharing feature, applicable to the effects of both recorded expense and capital additions, ensures a fair sharing with ratepayers of benefits if SCE manages SONGS in a superior manner.
- The average capacity factor for the SONGS units during the eight-year period that ICIP in effect (1996-2003) was 89.6%, the highest of any eight-year period in the plant's history. Since under the CCIM

> SCE will recover a fixed cent per kWh price for its share of actual SONGS generation, its ROR for its SONGS operations will be influenced by plant output as well as by cost control. Thus, under the CCIM, SCE's shareholders will benefit if SCE achieves high plant capacity factors. Because the cost of incremental power output from SONGS is so much less than the cost of obtaining the same amount of power from any other higher priced resource, there is a large benefit for ratepayers from achieving an increased capacity factor. Conversely, if SCE is not able achieve high plant capacity factors and as a result exceeds the CCIM cents per kWh price target approved by the Commission in this case, SCE's actual earned ROR for its SONGS operations will fall and SCE's shareholders will share in the resulting economic penalty.

SDG&E acknowledges that its proposed CCIM will require considerable further scrutiny and in all likelihood revision to accomplish the objectives of including appropriate service and safety standards and ensuring fairness of affected stakeholders. It was for this reason that SDG&E's proposal included a request that, if the Commission concludes that such PBR mechanism could better serve to cause SCE to become more efficient in managing costs at SONGS, a second phase of this proceeding immediately be commenced to take up this subject in great detail to determine whether such a mechanism could be structured to meet competing objectives.

22.3 SCE's Response

SCE asserts that SDG&E's proposed CCIM is seriously flawed and should be rejected in this phase of the proceeding as well as for further review in a later phase. SCE argues that the proponent of an incentive ratemaking mechanism must show why the proposed rewards/penalties provide improved service as compared to traditional cost-of-service ratemaking. SCE claims that

SDG&E did not show that its CCIM would result in better service for ratepayers than traditional cost-of-service ratemaking for SONGS 2 & 3. SCE also claims that adoption of CCIM could ultimately deprive ratepayers of the benefits of power from SONGS 2 & 3.

SCE is concerned that CCIM would apply incentives/penalties only to SCE and would allow use of a two-way balancing account for recovery of SDG&E's SONGS 2 & 3 operating costs. According to SCE, this would transfer all SONGS 2 & 3 operating risk from SDG&E's shareholders to its ratepayers. However, SCE does not necessarily oppose Commission adoption of different types of ratemaking for SCE's and SDG&E's SONGS 2 & 3 operating costs, if such ratemaking appropriately balances incentives/penalties for both utilities. For example, SCE states that it would not oppose use of traditional cost-of-service ratemaking for recovery of its SONGS 2 & 3 operating costs and appropriately designed balancing account treatment for recovery of SDG&E's SONGS 2 & 3 operating costs.[141] However, according to SCE, the aspects of the CCIM that would apply to it are so seriously flawed that the Commission should not adopt it under any circumstances.

SCE argues that SDG&E's proposal that none of the penalties or benefits should apply to SDG&E inappropriately ignores the fact that SDG&E can influence management of SONGS 2 & 3. SCE states that SDG&E has the right to not approve a budget that it reasonably disagrees with and refers to SDG&E's statement that: "[t]he Operating Agreement contemplates that SDG&E

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[141] SCE notes that in a settlement agreement on cost recovery for its investment in Palo Verde adopted by the Commission in D.96-12-083, SCE agreed to balancing

Footnote continued on next page

and the other minority owners have certain rights, *e.g.,* to approve budgets, which must be done on a unanimous basis."[142] SDG&E can request information concerning costs at SONGS 2 & 3, and SCE indicates that it welcomes such requests and works hard to try to respond to them. It is SCE's position that, even though SDG&E is not the Operating Agent for SONGS 2 & 3, it does have input to SONGS 2 & 3 management and its incentives/penalties for safe, reliable, and compliant operation of SONGS 2 & 3 should be aligned with SCE's incentives/penalties.

Regarding SDG&E's analysis that supports its CCIM proposal, SCE makes the following arguments:

- In the Test Year 2006 GRC, the Commission will set cost recovery ratemaking for SONGS 2 & 3 O&M and capital expenditures for 2006-2008. In 2006, SCE forecasts $234.9 million (2003 $, 100% share) of Base O&M expenses and $61.2 million of RFO expenses per unit per outage for SONGS 2 & 3. These O&M expenses are not subject to a later true-up. They will set SCE's recovery of SONGS 2&3 O&M expenses for the years 2006-2008. Correctly forecasting O&M expenses is critical to match operating costs with authorized revenues. SDG&E offers no evidence on SCE's ability to forecast SONGS 2 & 3 O&M expenses other than noting that "SCE generally adheres to the annual budgets that are presented to the Board of Review (BOR) each January for approval."[143]

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account treatment for its share of Palo Verde operating costs subject to reasonableness review if certain cost thresholds were exceeded.

[142] Exhibit 721, p. JA-8.

[143] Exhibit 721, p. JA-7.

- SDG&E's focus on SCE's ability to forecast capital expenditures at SONGS 2 & 3 five years in the future is misplaced. As SCE also stated in its Rebuttal Testimony, Exhibit 89, "[n]uclear power plant capital costs are particularly uncertain because events beyond the control of the utility affect the need to complete capital projects at a nuclear power plant." As SCE noted in its Rebuttal Testimony, Exhibit 89, SDG&E's testimony acknowledges that SCE could not reasonably foresee events beyond its control and their effects on SONGS 2 & 3 costs. In this docket, SCE forecasts capital expenditures for years 2004-2008. None of the SDG&E materials demonstrate that SCE's capital expenditures forecast in this docket is wrong. If SCE's forecast is necessarily wrong, SDG&E offers no other forecast that it argues is more correct, only a punitive performance-based ratemaking mechanism from which it proposes to exempt itself.
- SDG&E's benchmarking study is based on FERC Form 1 data from other utilities for 1990-2003 and observations from SONGS 2&3 for 1993-2004. Most of this data is for years prior to 2000. The September 11, 2001 terrorist attacks significantly increased security costs at SONGS 2 & 3 and at nuclear plants throughout the United States. SDG&E's benchmarking study does not fully take into account Nuclear Regulatory Commission (NRC) orders on nuclear security issued in 2003 requiring full compliance by October 2004. Therefore, they cannot provide an effective benchmark for SONGS 2 & 3 costs in 2006-2008.
- SDG&E's benchmarking study contains serious flaws in its measurement of costs and cannot be relied upon to assess the cost performance of SONGS 2 & 3. First, Dr. Lowry's study in this docket "commingles the costs of items, which are consumed at or near the time of purchase, such as labor and materials

included in Operation and Maintenance expense, with the cost of long-lived capital assets." Second, Dr. Lowry's previous benchmarking study, submitted to this Commission on behalf of SDG&E and its affiliate Southern California Gas Company, calculated the cost of capital used in production as the product of capital quantity index multiplied by a rental rate, which includes factors for depreciation, return and taxes. In contrast, Dr. Lowry's benchmarking study in this application uses only an incremental capital cost measure. Incremental costs in any given year only take account of capital additions in that year, and completely ignore the cost associated with all capital additions from prior periods, including the capital installed when the plant was originally completed.

- SDG&E's benchmarking study compares costs of utilities with portfolios of nuclear plants to SONGS 2 & 3, which is a single plant site. SCE has ownership interests in SONGS 2 & 3 and Palo Verde. SDG&E should have compared (1) SCE's nuclear plant portfolio to those of other utilities, or (2) costs of individual nuclear plant sites with SONGS 2 & 3 costs. SONGS 2 & 3 cannot be appropriately compared to other utilities with nuclear plant portfolios included in SDG&E's sample group. In addition, costs from a portfolio would reflect an optimization decision that is not available for a single plant.
- Finally, and more generally, SDG&E still had data errors in its last errata with the following variables: (1) plant age; (2) percentage of plant owned; and (3) acreage.

SCE states that the proposed CCIM could increasingly constrict its ability to earn its authorized return on SONGS 2 & 3 investment. According to SCE, earnings on rate base will dwindle while incentive ratemaking

opportunities to realize earnings through O&M cost savings compared to O&M forecasts adopted by the Commission are limited by resetting rates every three years. Also, the CCIM would place the burden of carrying costs on SCE's shareholders for capital additions which may not go into service for several years, such as reactor pressure vessel head replacements. SCE also states that the purpose of CCIM sharing bands is unclear and the CCIM penalizes SCE for fluctuations in cost that could be caused by such normal events as simply having two refueling outages in a single year.

It is SCE's position that it will not operate SONGS 2 & 3 unless it is assured it has an opportunity to access adequate resources to ensure public safety, compliance with regulatory requirements, and adequate reliability. SCE argues that SDG&E's proposed CCIM does not help SCE further those goals. If SCE has no opportunity to ensure access to adequate resources for public safety, compliance with regulatory requirements and adequate reliability, it states that it would have to close SONGS 2 & 3 and deprive ratepayers of both utilities of low cost power from SONGS 2 & 3.

22.4 Discussion

Whether SDG&E has any influence in controlling spending at SONGS is debatable – SCE says yes; SDG&E says no. We would however agree that SDG&E has less control than they would if they operated the plant. It is similar to SCE's position as minority owner of the PVNGS 1-3. However, as discussed below, we are not convinced that an incentive mechanism at this time will necessarily lead to lower costs, over the long term, than would occur under normal cost of service ratemaking. While somewhat sympathetic to SDG&E's situation, we decline its request to adopt the concept of its proposed CCIM. We

will continue to evaluate and set authorized levels of rate recovery for SONGS on a cost of service ratemaking basis.

Regarding SDG&E's benchmarking study, while such information would be helpful in our decision making, consideration of SCE's criticisms reduces our confidence in the study to the extent that we do not feel comfortable in making wide-ranging decisions based on the results. It is reasonable that the study should correctly reflect such factors as plant age, percentage of plant owned and acreage. Also SCE reasonably argues that SONGS 2&3 should be compared to costs of nuclear plant sites, not nuclear portfolios of other utilities. Possible commingling of O&M and capital costs and use of incremental plant additions rather than also considering costs of embedded plant also are concerns.

SDG&E's analysis of the ICIP benefits focused on capital expenditures. Data presented clearly shows that during the ICIP years, SONGS capital expenditures were lower than in the Pre-ICIP and Post-ICIP years. What is not clear is why expenditures were so much lower in the ICIP years. SDG&E shows that in the Pre-ICIP years, annual capital expenditures ranged from approximately $50,000,000 to approximately $160,000,000. During the ICIP years annual capital expenditures ranged from approximately $18,000,000 to approximately $57,000,000. In 2004, the recorded capital expenditures were $143,000,000, and the forecasts for 2005 to 2007 are between $100,000,000 and $120,000,000 per year. We are less concerned about the differences between preliminary budgets and recorded costs than we are about the variance in the magnitude of the recorded capital costs over time. If we felt certain that an incentive mechanism would somehow reduce the capital expenditure levels to those experienced during the ICIP years, it would be foolish not to adopt a mechanism which reflects that reduced spending in the base amount. However,

even though SDG&E is concerned that recorded/forecasted costs have increased over preliminary budget amounts, it does not assert that any of the recorded or forecasted expenditures costs are unnecessary or unreasonable. In fact, at this point in this GRC, there is only one issue related to SCE's forecasts for specific SONGS capital projects even though the forecasted expenditures are significantly higher than that experienced during the ICIP years.

SDG&E acknowledges there may be cost increases related to events, such as that of September 11, 2001, that are beyond SCE's control. However, SDG&E sees the increased costs of such events as reflective of SCE's inability to forecast costs at SONGS' because these costs are inherently uncertain with a high likelihood of very large increase in capital cost exposure, including exposure from events beyond the control of the utility. Such exposure may be exasperated by SDG&E's proposal to expense the costs over one year. While unanticipated costs are also not reflected in cost of service ratemaking, the utility is only denied cost recovery until the next GRC. At that point, assuming reasonableness, the utility can recover costs relate to the undepreciated amount over the life of the asset. From SDG&E's explanations, it appears that if feels it is more likely that capital expenditures will increase rather than decrease. In that sense, the proposal does not appear balanced. Without providing some offsetting benefit to SCE, it is not reasonable or fair to establish an incentive mechanism that is developed to expose SCE to the effects of acknowledged potential unknown cost increases, especially those that are beyond its control.

The value of the CCIM when compared to cost of service ratemaking is also speculative. There is always an incentive for the utility to incur lesser costs than that forecasted to set rates. The utility's shareholders would benefit fully to the extent that occurred. Likewise, there is no incentive for SCE to

unnecessarily spend more than authorized, since its shareholders would be responsible for all cost overruns. Under the CCIM proposal, there would be sharing bands, with details to be worked out in a subsequent phase to this proceeding. SDG&E provided an example where SCE would be responsible for 100% of the costs or the first 50 basis points around the benchmark rate of return. Between 50 and 100 basis points there would be a 50%/50% sharing with ratepayers. The shareholder share would then increase in steps back to 100% with a suspension of the mechanism if the spread is greater than 300 basis points. Regular cost of service ratemaking provides a greater incentive to control costs, because, under cost of service ratemaking, SCE would be responsible for all overruns and would keep all savings during the rate case cycle as opposed to, under the CCIM, potentially only having to absorb a portion of cost overruns and being able to only share in a portion s of cost underruns. Under typical PBR mechanisms with sharing mechanisms, a utility might pursue cost savings, because even though there may be sharing with ratepayers, the benefit of the savings would be realized over a substantially longer period than the normal GRC cycle. However, under the CCIM proposal, costs would be reevaluated in the next GRC. Realized cost savings might then be reflected on a forward looking basis in rates for the next GRC cycle. This negates some of incentive for the utility to pursue cost savings and reduce costs.

We do recognize that the CCIM proposal to expense capital additions will provide additional incentives to maintain capital spending below authorized levels, because, as SDG&E indicates, there is no future truing up of recorded costs in rates since the costs are only reflected in one year, not over the life of the asset or plant. The converse is also true, if a capital project comes in below budget, the whole benefit is reflected in one year and there is no truing up of the

reduced cost in rates to be reflected over the remaining life. However, the proposal to expense capital additions may actually provide an incentive for SCE to defer projects that might otherwise be built. Some projects might be deferred for a short period to capture the differential between authorized and recorded amounts up front. Other projects based on cost benefit analyses may be deferred only because the effect of expensing the project in one year may not, from the utility's perspective, be offset by the resultant cost savings. Such cost savings may not even fully occur until the next GRC at which time, under the CCIM proposal, the savings might be then reflected in rates. Whether or not such deferrals occurred during the ICIP period is uncertain, but considering the reduced capital spending during that period when compared to the prior and subsequent periods, it is something to at least consider going forward.

It is for the reasons above that we decline to adopt SDG&E's request to establish its proposed CCIM. SCE indicated that it would not oppose the use of traditional cost-of-service ratemaking for recovery of its SONGS 2 & 3 operating costs and appropriately designed balancing account treatment for recovery of SDG&E's SONGS 2 & 3 operating costs. SDG&E indicates such a proposal would be acceptable with certain conditions. There may be merit in establishing a balancing account mechanism for SDG&E's share of SONGS costs. However, such a mechanism would transfer the cost recovery risk from SDG&E's shareholders to SDG&E's ratepayers. There would be no effect on SCE's shareholders or SCE's ratepayers. For this reason, it would be more appropriate that any consideration of such a balancing account for SDG&E be considered in the context of SDG&E's next general rate proceeding, where overall shareholder and ratepayer risks and benefits can be evaluated in a more cohesive manner.

Lastly, SDG&E's stated preference is to sell its share of SONGS to SCE and instead receive energy through a negotiated purchase power agreement. SDG&E is pursuing such a course of action in the steam generator proceeding. If unsuccessful, it might pursue this goal in other venues. SDG&E has stated that if such a proposal is adopted by the Commission, it would withdraw it CCIM proposal. It may be worthwhile to defer significant ratemaking changes, such as the proposed CCIM, until there is more certainty that such proposed changes are really necessary.

23. Distribution Reliability Incentive Mechanisms

Since 1997, SCE has been subject to a form of reliability incentive mechanism in which it could earn rewards or suffer penalties depending on its performance relative to benchmarks for the frequency of electric service interruptions and duration of those interruptions. The first such mechanism was adopted for SCE in D.96-09-092. More recently, the Commission authorized a modified version of a distribution reliability mechanism in SCE's test year 2003 GRC.

In this 2006, GRC, SCE, CUE, DRA, TURN and Aglet each presented testimony and filed briefs on what the Commission should authorize regarding distribution reliability incentive mechanisms in the 2006-2008 period. SCE's primary position, as reflected in testimony and briefs is that the type of incentive mechanism currently in place for SCE is no longer in the best interests of it or its customers. In summary, SCE contends that an incentive mechanism based on short-term measurement simply exposes customers and shareholders to rewards/penalties due to random events, and does not create incentives for achieving satisfactory levels of long-term reliability. Instead, SCE proposed to report annually to the Commission on its reliability performance relative to a

peer group of utilities based on information supplied by those utilities to the Edison Electric Institute.

CUE's primary position, as reflected in its testimony and briefs is that the Commission should continue the kind of reliability incentive mechanism currently in place, but with certain changes. In summary, CUE contends that its mechanism will create necessary incentives for both short and long-term reliability, and will create a disincentive for SCE management to reduce its current reliability-related investments by diverting investments to other areas of company operations.

In its testimony and briefs, TURN supported SCE's recommendation to eliminate the incentive mechanism. TURN argued that if the Commission were to adopt a mechanism, it should include much more stringent targets to ensure that ratepayers pay incentives only for performance incremental to performance already funded through rates.

At this time, SCE, CUE and TURN have agreed on a reliability investment incentive mechanism which is explained and addressed below.

Aglet opposes corporate performance incentives that allow financial rewards and penalties for SCE. It is Aglet's position that these types of performance targets duplicate existing executive goals and are not necessary. However, Aglet supports monitoring of utility performance, in order to remind utility managers of the Commission's interest in specific areas of their operations.

DRA has proposed an alternative reliability accountability mechanism which is explained and addressed below.

23.1 Reliability Investment Incentive Mechanism

23.1.1. Background

Throughout this proceeding SCE, CUE, and TURN engaged in discussions aimed at resolving their differences on distribution reliability incentive mechanisms. Discussions between SCE and CUE did not culminate until October 19, 2005, when SCE and CUE agreed in principle on a fair resolution of these issues, which was documented in a Memorandum of Understanding. A duly noticed Settlement/Stipulation Conference was held on October 27, 2005, with participation by representatives of SCE, CUE, TURN, DRA, Aglet, and SDG&E. Following the Settlement/Stipulation Conference, SCE and CUE attempted to respond to some of the issues discussed during the Settlement/Stipulation conference and engaged in further negotiations with TURN. Those discussions with TURN culminated on November 1, 2005, when TURN agreed in principle to join in the stipulation provided SCE and CUE agreed to certain terms, which have been reflected in the stipulation.

On November 2, 2005, SCE, CUE and TURN (Settling Parties) submitted a joint motion for approval of a stipulation on the Reliability Investment Incentive Mechanism (RIIM). Aglet filed comments on the stipulation on November 16, 2005 and DRA filed comments on November 17, 2005. SCE and CUE jointly replied to the comments of Aglet and DRA on November 23, 2005.

23.1.2. Terms of Stipulation

The Settling Parties' stipulation regarding the RIIM is included in this decision as Appendix E. Briefly:

- The RIIM will be in effect upon the effective date of its adoption by the Commission and run through December 31, 2008.
- The Settling Parties have identified certain categories of SCE's capital expenditure request in this proceeding that are particularly related to preserving long-term electric service reliability for SCE's customers. Based on the record presented in this proceeding, the Parties have designated these certain capital expenditures and the associated cumulative capital additions forecast to be added to plant-in-service by December 31, 2008 (plus the associated cost of removal) as subject to the RIIM.
- The Settling Parties also agree that adequate recruitment and retention of apprentice Linemen/Groundmen, and their training represents an important indicator of SCE's ability to preserve long-term electric system reliability.
- SCE agrees to add a cumulative total of 600 apprentice Linemen/Groundmen to its workforce during 2006-2008.
- At the end of 2008, SCE will compare the adopted RIIM capital additions (plus associated cost-of-removal) with the adjusted recorded RIIM capital additions from the effective date of the GRC final decision through December 31, 2008. This difference, if any, is the "Cumulative Shortfall."
- The capital-related revenue requirement associated with any Cumulative Shortfall, plus associated interest will be returned to SCE's customers as a balancing account credit.
- If SCE's cumulative increase in apprentice Linemen/Groundmen is less than 600 employees, but is greater than 500 employees, SCE will return to customers an amount calculated as follows:

$15 thousand multiplied by (600 - the increase in apprentice Linemen/Groundmen).

- If the cumulative increase falls below 500 such apprentice Linemen/Groundmen, the amount returned to customers would include the calculation from Section 3.6.5 (*i.e.*, $15 thousand multiplied by 100 apprentice Linemen/Groundmen, or $1.5 million), plus an additional concurrent amount calculated as follows: $70.5 thousand2 multiplied by (500 - # increased).
- For six months during 2006, SCE will record its outage information and tabulate "SAIDI," "SAIFI" and "MAIFI" values using both its existing "DTOM" system and its new "ODRM" system. The results of this dual recording will be made publicly available so that parties can compare the outage metrics produced by the old and new systems.

23.1.3. Discussion

We approve the Settling Parties' stipulation regarding the RIIM, although we are somewhat concerned about the actual incentive. The incentive is not to maintain or improve distribution reliability, but rather to spend money on projects or activities that will likely maintain or improve distribution reliability. Whether spending the money actually accomplishes anything is not tied to the RIIM.

However, we approve the use of the RIIM, because we feel the related expenditures that are adopted in this decision are necessary. The adoption of the expenditures, much of which was in excess of what historic data would indicate was reasonable, was influenced, to a great extent, by the importance placed on them by SCE. While we expect SCE to spend its authorized amounts for these categories, the RIIM provides an incentive for them to do so and a means to credit money back to ratepayers if they do not do so.

In approving the use of the RIIM, we are at the same time rejecting the continued use of an incentive mechanism with rewards and penalties. SCE argues that:

- The existing distribution reliability mechanism has not improved SCE's reliability.
- The distribution reliability mechanisms have attracted a great deal of management time and attention that could be better used to address more significant issues such as the efficient replacement of SCE's aging infrastructure.
- The primary contributors to unreliability are either causes over which SCE has little or no control (*e.g.*, unavoidable operational activities, third party, and weather) or equipment failures. While SCE clearly has control over the number of equipment failures over the long term, *i.e.*, through a program of infrastructure replacement, the effects of infrastructure replacement cannot be immediately seen.
- The costs to ratepayers of the reliability mechanisms proposed in this proceeding have not been assessed. It is possible that the amount of money required to meet the proposed targets would far exceed what ratepayers would be willing to fund.

SCE's recommendation to discontinue its current reward/penalty reliability incentive mechanism was supported by TURN and Aglet. We are persuaded that such incentive mechanisms are not appropriate at this time. Also as discussed later, we do not adopt DRA's proposed reliability mechanism.

There are two elements of the stipulation, which are opposed by other parties. The first is the proposal to require SCE to make capital additions

in the amounts found to be reasonable by the Commission. While DRA does not object to this element, Aglet sees the proposal as a shift toward recorded cost ratemaking. Aglet states that the balancing account feature would result in authorizing recorded cost ratemaking for revenue requirements that would normally be set on a forecast basis. Aglet explains that if SCE in 2006 spends more than authorized amounts on the functions that are subject to the RIIM, it will be allowed to offset those costs against underspending in the two subsequent years. This would undermine SCE's incentive to control its test year costs, and would give SCE a perverse incentive to shift costs from other company functions into accounts protected by the RIIM. Consequently, price and spending risks will be transferred from the utility to ratepayers, without adequate compensation or offsetting benefits.

We do not view the RIIM as a step toward recorded cost ratemaking. Rates related to the expenditures at issue are set on a forecasted basis. Certainly, SCE can overspend in one year and underspend in other years. This is the case even under forecasted cost ratemaking. However, under the RIIM as well as under forecasted cost ratemaking, SCE does not receive additional funding if it spends more than authorized. Rates will not be adjusted to reflect recorded amounts. Therefore there is no incentive to shift costs to RIIM accounts, and there is no additional risk to ratepayers. However, if SCE spends less than authorized over the GRC cycle, under the RIIM, it will credit ratepayers for the difference between recorded and authorized spending. Only in that sense does the RIIM reflect recorded cost ratemaking. However, the risk to ratepayers is less under the RIIM, because SCE must credit ratepayers if it spends less than authorized. Under forecasted cost of service ratemaking, the company could use that that amount for other purposes, including payment to shareholders. For

these reasons, we do not view the RIIM as a shift toward recorded cost ratemaking, but merely a commitment to spend money for reliability purposes, to the extent that it is authorized.

Aglet also criticizes this element of the stipulation as being unnecessarily complex in that the Settling Parties do not specify how the stipulation will calculate 2007 and 2008 revenue requirements subject to the RIIM, based on 2006 capital expenditures. For example, test year 2006 expenditures for pole replacement and load growth will decline in the following two years. According to Aglet, while the stipulation asks the Commission to identify any reductions to SCE's requested 2006 through 2008 amounts that would be subject to the proposed RIIM, it is incomplete because it offers no method or basis for making such reductions. Aglet asserts that this omission will lead to uncertain ratemaking and unnecessary technical disputes.

The RIIM does add a level of complexity to the process. However, it does not affect the rates that are set for 2006, 2007 or 2008. The complexity relates to determining what levels of expenditures for certain particular cost categories will be subject to SCE's commitment to either spend the authorized levels or credit any underspent amount back to ratepayers. Since the settling parties have agreed what those levels should be based on SCE's request, they should be able to determine what the levels should be based on the results of this decision. Therefore, based on the results of this decision, the Settling Parties should jointly determine the levels of expenditures that will be subject to SCE's commitment to either spend the authorized amounts or credit ratepayers for the underspent amounts. When SCE files its compliance advice letter to submit the preliminary statement to establish the operation of the RIIM, it should include that jointly determined information, with supporting workpapers. If

non-settling parties dispute the Settling Parties' determination, they should protest the advice letter filing. The Energy Division will resolve the matter.

The second element of the stipulation that is opposed relates to the addition of 600 apprentice Linemen/Groundmen to SCE's workforce over the three-year GRC cycle.

DRA asserts that the Settling Parties have failed to meet the burden of proof for adoption of an incentive mechanism and have not shown that the stipulation as to the 600 additional employees is reasonable in light of the record, consistent with law, or in public interest. We are not persuaded by DRA's arguments.

DRA's assertions seem to revolve around the assumption that 600 additional positions are being added by the stipulation to specifically address reliability problems. From its comments, Aglet also seems to be under the impression that the RIIM will cause the addition of 600 additional employees. However, SCE has made it clear that it is not requesting additional funding for the 600 additional Linemen and Groundmen because of the RIIM. This additional workforce was assumed in SCE's original application showing. SCE originally projected a need to hire 180 apprentice and journeymen Linemen per year. For the RIIM target of 600, it was decided to include 60 Groundmen over the GRC cycle. The reasonableness of the additional Linemen/Groundmen was addressed in SCE's direct showing and rebuttal.

In general we do not micromanage the utility's operations. Whether SCE adds 600 Linemen/Groundmen is secondary in importance to the total net workforce that is reflected in our determination of reasonable O&M and capital expenditures. However, in considering the RIIM we should address the addition of 600 Linemen and Groundmen, to determine if is reasonable for RIIM

purposes. What this number should be, given the results of our decision today, is unknown. In general, additional Linemen/Groundmen will either replace exiting jobs that are vacated due to retirement or other reason, be used to reduce overtime for ongoing activities, be used to replace contract workers, or be used to perform new or expanded work activities. Considering what is reflected in SCE's test year estimates and given all the different ways in which the additional Linemen/Groundmen can be used, it is reasonable to assume that 600 additional Linemen/Groundmen can be accommodated within the revenue requirement authorized by this decision.[144]

DRA also criticizes the stipulation for not demonstrating how, and to what extent, the 600 additional Linemen/Groundmen will contribute to maintaining or improving reliability. We take the view that the additional Linemen and Groundmen are embedded in the workforce that is necessary to accomplish the activities authorized in rates by this decision. Maintaining reliability is a primary focus of many of those activities. Without a sufficient workforce, reliability can only suffer.

In considering all of the above, we are convinced that the stipulation regarding the RIIM is reasonable in light of the record, is consistent with law, is in the public interest, and should be approved.

23.2 Reliable Distribution Accountability Mechanism

It is DRA's position that some form of financial accountability is necessary, if SCE's ratepayers are to receive a level of service reliability

[144] It is our understanding that SCE has committed to add the 600 new linemen/groundmen no matter what level is set by this decision for T&D O&M or capital expenditures.

commensurate with the rates they are paying. DRA proposes the Reliable Distribution Accountability Mechanism (RDAM) to meet that objective.

DRA's single index starts with the average of SCE's results from 1999 – 2003 for SAIDI, SAIFI and MAIFI to arrive at an expected level for each. DRA then adds a margin to establish a penalty threshold value. SAIDI and SAIFI values have equal weights of 45%. MAIFI is weighted at 10%. Using DRA's reliability index, acceptable performance on one measure can offset poor performance on another. DRA's mechanism also includes a storm adjustment, and allows exclusions for specified "major events" so that SCE is not held responsible for outages that SCE could not reasonably have anticipated. The single index will measure whether SCE has provided a total level of service that is acceptable. The index value measures performance relative to a score of 100, with scores below 100 representing improvement in total reliability performance. The RDAM would impose a penalty of $2,250,000 per percentage point above 100.

DRA asserts that its RDAM is reasonable because (1) it provides ratepayers some protection if SCE's system reliability declines below even minimally acceptable standards; (2) it is not a punitive measure although it provides for specified consequences; (3) the minimum level of reliability is condition-based -- there is one minimum level for a broad range of normal conditions, and a higher acceptable level of outages to account for adverse weather conditions; and (4) SCE may seek penalty mitigation or waiver upon showing that new and unanticipated circumstances caused SCE to exceed the penalty threshold.

SCE states that the proponents of distribution reliability mechanisms have failed to support the investment needed to maintain reliability, specifically,

noting that "DRA proposes SCE be penalized for failing to meet DRA's proposed reliability benchmark, while at the same time proposing draconian cuts to SCE's proposed investments to replace aging, and increasingly failure-prone distribution infrastructure." SCE also asserts that DRA's proposal is not cost effective, because holding reliability at a constant level going forward would require extraordinary amounts of infrastructure replacement, far beyond what is requested in the GRC.

23.3 Discussion

The intent of the RDAM to hold SCE accountable for what it receives in rates is a worthy goal. DRA disputes SCE's contention that its system is aging and points to projects such as distribution automation that should improve reliability. However, although DRA proposes that reliability levels only be maintained and not improved, it has not provided any guidance as to what level of spending is necessary to do so. Whether it can be accomplished under DRA's proposed revenue requirement or even under SCE's proposed revenue requirements has not been substantiated. In this decision, we have acknowledged that SCE's distribution infrastructure is aging and that there are attendant problems associated with such aging. We are reluctant to impose an incentive mechanism such as that proposed by DRA without more information that can substantiate the level of expenditures necessary to maintain distribution reliability levels.

We believe that the RIIM accomplishes the same goal as the RDAM in that it holds SCE accountable for distribution reliability related funds that it receives in rates. However, the RIIM directly relates to what we are authorizing in rates. If SCE does not spend the authorized amounts of money on those particular reliability related items, that money will be returned to ratepayers. At

this time, we believe the RIIM is a fairer and more appropriate mechanism to address this aspect of distribution reliability. Therefore, we will not adopt DRA's proposed RDAM.

24. Employee Safety Incentive Mechanism

CUE proposes that SCE continue the existing employee safety incentive mechanism. According to CUE there is no dispute that (1) over the past 10 years, OSHA recordable injuries (the safety metric) have been reduced by about two-thirds; (2) this statistic represents a genuine improvement in employee safety; or (3) the Commission's incentive mechanism has been helpful in reducing SCE's injury rate.

CUE proposes that the mechanism be structured like the former mechanism, but with a new performance target. The target would be an OSHA reportable level of approximately 2.7, based on a downward trend in earlier years.

SCE opposes the continuation of the employee safety incentive mechanism at this time. SCE indicates that it voluntarily reported, to the Commission, results of an internal investigation that found the company's injury and illness data was unreliable. It was determined that SCE did not accurately track the number of first aid treatments (*e.g.,* such as small cuts requiring band-aids and sprains requiring cold- or hot-packs, or over-the-counter medication), cases involving hearing loss, and some OSHA recordable work injuries. SCE states that first aid work injuries and minor OSHA recordable work injuries are very difficult to track consistently, making it difficult to establish targets and assess performance in these areas. SCE indicates that it is strongly committed to protecting the safety of all SCE personnel and that safety performance incentives have been an important part of its safety programs. However, in view of the

findings of its internal investigation that, SCE feels the employee safety mechanisms should be temporarily suspended to give the company time to evaluate alternative safety performance measures and to establish reliable safety performance baselines in order to set appropriate performance targets.

CUE argues that minor imprecision in the baseline data is not a good enough reason to terminate the incentive. It continues to assert its position that, given the success of the employee safety incentive measure over the past 10 years, and the importance of protecting the safety of employees in a dangerous occupation, the Commission should continue the incentive measure as proposed by CUE.

24.1 Discussion

For any incentive mechanism, when ratepayer/shareholder funds are at stake, we must ensure that the disposition of any rewards or penalties is based on a fair and unbiased process. Consistency of reporting is extremely important in order to fairly establish targets and assess performance. SCE's problems in this regard do not reflect a minor imprecision, as characterized by CUE. There is a question of whether OSHA reportable injuries are even an appropriate measure for developing safety incentives. Because of this, it is not reasonable, at this time, to continue the employee safety incentive mechanism. It should be discontinued for the test year 2006 GRC cycle. In its next GRC, SCE should report on its evaluation of the reliability of its injury and illness data and address its concern about whether OSHA recordable injuries should be used as the basis for an employee safety incentive mechanism. SCE should also provide information or measurable data that demonstrate that, absent the incentive mechanism, the company has made, and will continue to make, employee safety a high priority during the full term of this GRC cycle.

25. Bill Calculation Services for Mobile Home Parks

25.1 Background

On March 23, 2005, the WMA filed a motion seeking a ruling that two issues are within the scope of Phase 1 of SCE's test year 2006 GRC and should be addressed in this proceeding. The two issues identified by WMA were as follows:

1. Are there fair and reasonable ways to mitigate the cost to MHP owners of converting existing submetered systems to directly metered service? (Conversion issue.)
2. SCE should provide an analysis of the costs, benefits and feasibility of providing bill calculation services to MHP owners, examples of the appropriate tariff language and an estimate of the rates necessary to recover the full costs of such service from MHP owners. (Billing issue.)

According to WMA, these issues were the subject of the Commission's investigation into the master meter discount in R.03-03-017 and I. 03-03-018. WMA stated that in D.04-11-033, the Commission directed that these issues be considered on a case-by-case basis outside the rulemaking/investigation and that it now seeks to properly include them in this proceeding.

The conversion issue was considered, but not fully developed in R.03-03-017/I.03-03-018. The active parties in that proceeding filed a motion seeking to establish a separate proceeding to address whether there are fair and reasonable ways to mitigate the cost to MHP owners of converting existing submetered systems to directly-metered service. The parties contended that the issue would be complex and wide-ranging, and involve questions that would require significant discovery, hearings and briefing. For that reason, it appeared

that consideration of the conversion issue in SCE's current GRC would unduly affect the established procedural schedule. D.04-11-033 denied the parties' motion to establish a separate proceeding and stated this issue is reserved for consideration in a future proceeding.[145] An ALJ Ruling, dated April 22, 2005, stated that the conversion issue should be addressed when that future proceeding is identified and instituted. WMA's request to add the conversion issue for consideration in this GRC was then denied.

Regarding the billing issue, in D.04-11-033, the Commission stated:

> "The utilities are far more knowledgeable about how to calculate utility bills than the MHP owners. Therefore, having the utilities offer bill calculation services to MHP owners should be considered as a possible way to ensure that tenants are correctly billed, and receive any discounts or refunds to which they are entitled. To do this, it will be necessary to consider the costs and benefits, as well as any other relevant matters. Therefore, we will require the utilities to provide an analysis, in their next revenue requirement proceedings, of the costs, benefits, and feasibility of providing bill calculation services. The utilities will also be required to provide examples of the appropriate tariff language, and an estimate of the rates necessary to recover the full costs of the services from the MHP owners. With this information, the matter can be fully considered in those proceedings."[146]

The April 22nd Ruling granted WMA's request to consider the billing issue in the revenue requirement phase of this GRC. Arguably, the next revenue requirement proceeding for SCE would have been its next filed GRC, probably

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[145] *See* D.04-11-033, Ordering Paragraph 13, as modified by D.05-04-031.

[146] D.04-11-033, *mimeo.*, p. 31. Also, *see* Ordering Paragraph 12.

for test year 2009. Even though D.04-11-033 was issued on November 19, 2004, and mailed on November 24, 2004, both of which dates were in advance of SCE's GRC application filing on December 21, 2004, the timeframe in which SCE could have developed the required analysis of billing service costs, benefits and feasibility and included it in its showing for the test year 2006 GRC would have been prior to the October 22, 2004 acceptance of its notice of intent to file the GRC application. However, delaying consideration of this issue for SCE until its next GRC for test year 2009, at the earliest, was not considered to be in the public interest. The April 22nd Ruling stated that a timelier implementation of the directives of D.04-11-033 should be accomplished for SCE by considering the issue now, as part of this proceeding.

A prehearing conference was held on May 6, 2005 to consider matters related to inclusion of the billing issue in this GRC. In accordance with the determined schedule, SCE served testimony on July 15, 2005, regarding the costs, benefits, and feasibility of providing bill calculation services on behalf of the owners or operators of submetered mobile home parks (MHPs). TURN served responsive testimony on August 15, 2005. SCE and WMA served rebuttal testimony on August 29, 2005. On September 1, 2005, SCE provided notice to all parties to this proceeding of the intent of SCE, TURN, and WMA to conduct a telephonic conference on September 8, 2005 related to potential settlement of issues in this proceeding. The conference call was conducted as scheduled, with representatives of SCE, WMA, TURN, and Pacific Gas and Electric Company in attendance. SCE, WMA, and TURN (the Settling Parties) reached a settlement that resolves all outstanding issues related to SCE's provision of bill calculation services for MHPs. A settlement agreement (Settlement) was executed on or

after September 8, 2005, and was attached to the motion. Evidentiary hearing was held on September 12, 2005.

25.2 SCE's Proposal

In its prepared testimony, subsequently identified as Exhibit 167, SCE stated its belief that it is feasible to offer a bill calculation service as described in D.04-11-033. In summary, SCE stated:

- To utilize SCE's proposed bill calculation service, MHP owners must enroll for the bill calculation service pursuant to an agreement for a minimum term of 12 months.
- MHP owners will be required to provide SCE with each tenant's rate schedule, billing period, and meter read information through a secured link at SCE's website.
- MHP owners will provide information such as metered usage data in a required format to facilitate the calculation. MHP owners will continue to take responsibility for the accuracy of the meter data.
- SCE will calculate submetered tenants' bills in accordance with the applicable SCE residential rate schedules and return the bill calculation information to the MHP owner.
- SCE will send the MHP owner a nonenergy invoice with service fee based on the number of tenant bill calculation transactions processed and the delivery method selected by the MHP owner. The MHP owner will be able to select from three options to receive each tenant's calculated electrical bill information: e-mail correspondence, compact disc, or paper copy.

- As required by D.04-11-033, the costs of this service must be recovered from the MHP customers.[147] Those MHP customers that enroll for this service will pay a separate monthly fee that is designed to recover SCE's costs of establishing this service. In addition, MHP owners will pay a transaction fee per each bill calculation, i.e., each time a tenant's bill is calculated and the results delivered to the MHP owner, to recover SCE's system costs and ongoing costs of providing this service.

Details of SCE's proposal, the costs and benefits associated with the proposed service, estimated calculation service fees, a proposed tariff and a proposed bill calculation service agreement were included in Exhibit 167.

25.3 TURN's Response

TURN was the only party that responded to SCE's proposal. In its testimony, TURN recommended adoption of SCE's proposal with the following modifications:

- The Commission should require SCE to offer one-time rebate, refund and credit calculation services as part of its bill calculation and presentation package, rather than offer the former as an optional "special service."
- The Commission should require that all park owners taking bill calculation services from SCE also distribute to tenants Edison's bill inserts pertaining to

[147] As designed, SCE's bill calculation proposal will not affect SCE's proposed revenue requirement in this proceeding. If charges collected from participating MHP customers do not recover SCE's development costs, SCE proposes to recover such incremental costs from all customers served on Schedule DMS-2 in a future proceeding. In SCE's next GRC, SCE will forecast the bill calculation service costs, and reassess the fees and participation levels in order to determine a revenue credit to be applied to SCE's overall revenue requirement.

the availability of utility programs such as the California Alternate Rate for Energy (CARE) program, the Family Electric Rate Assistance (FERA) program, and the Medical Baseline Program.

- The Commission should require SCE to retain three years of billing records for MHPs subscribing to its billing services, rather than the proposed one year. In addition, the Commission should ensure that Edison's service fees for providing bill calculation services to MHPs are calculated consistently with the credit DMS-2 customer receive in the DMS-2 submetering discount. Otherwise, SCE's purportedly ratepayer-neutral proposal may result in ratepayer subsidies to MHP master meter customers.
- The Commission should require Edison to update its proposed fees to 2006 dollars, as 2006 is the year when this service will most likely be implemented.

25.4 Rebuttal

SCE and WMA each served rebuttal testimony on August 29, 2005. SCE agreed with TURN's recommendations to retain tenant bill calculation records for a three-year period and to update the proposed customer charge and bill calculation transaction fees from 2004 to 2006 dollars. SCE also agreed to modify its proposal to include any applicable tenant refund or credit calculations as a mandatory part of the bill calculation service, with costs based on SCE's time and materials expense. Because SCE already provides application and renewal forms and certificates for CARE and FERA to MHP owners in June of each year, SCE opposed TURN's recommendation to provide bill inserts to MHP owners who subscribe to the bill calculation service for distribution with the tenant bills. WMA did not object to some of TURN's proposals, but raised concerns that TURN's recommendations would increase the cost of the bill calculation service, which would in turn reduce participation. WMA opposed TURN's

recommendation to require all mastermeter subscribers to the bill calculation service to have SCE calculate any applicable refunds or credits for submetered tenants because in part Pub. Util. Code § 739.5(b) applies a different requirement to the provision of refunds to submetered tenants of MHPs than applies to directly metered residential customers of the utility. WMA also opposed the imposition of any further notification requirements regarding rate discount programs as a requirement for subscription to the bill calculation service. WMA also noted several concerns regarding TURN's recommendation that SCE should be required to retain billing records provided by master-meter customers for a period of three years.

25.5 The Settlement

The Settling Parties agreed to resolve their differences as follows:

- The MHP owners or operators who subscribe to the bill calculation service shall pay for SCE to calculate any applicable tenant refunds or credits resulting from Commission orders or other mechanisms that would otherwise apply to directly-metered residential customers of SCE, and shall have such costs added when applicable to the customer charge or bill calculation transaction fees.
- No requirements to distribute bill inserts or post notices regarding the eligibility or availability of discounts to submetered tenants of MHPs in addition to those currently required for CARE, FERA, or medical baseline will be imposed on the MHP owners or operators by virtue of the customers' agreement to subscribe to SCE's bill calculation service.
- SCE shall retain for a three-year period the billing records of submetered tenants that are provided by subscribers to the bill calculation service.
- The customer charges, bill transaction fees, and any applicable costs for time and materials when

necessary to calculate submetered tenant refunds or credits shall be updated to current dollar costs, and reflected as a special condition in SCE's Schedule DMS-2.

- SCE customers shall be required to execute the Bill Calculation Service Agreement included in Appendix C of SCE's initial testimony, identified as Exhibit 167, as a condition of receiving the bill calculation service.

25.6 Discussion

The terms of the Settlement reasonably resolve differences between SCE's proposal and TURN's recommendations. Because SCE already provides application and renewal forms and certificates for CARE and FERA to MHP owners in June of each year, TURN's recommendation regarding related bill inserts or notice postings is not necessary. TURN's other recommendations are reflected in the Settlement.

The costs and revenues associated with this new service will not have any impact on the overall revenue requirement for SCE that will be determined in this proceeding. SCE's estimates of the costs to develop the billing system necessary for the service, to provide on-going services, and to maintain the systems are costs that are incremental to the costs identified in SCE's application and are not reflected in SCE's requested revenue requirement. The revenues generated from the proposed fees for the bill calculation service are designed to fully recover SCE's costs from MHP owners over five years based on forecast billing determinants. These revenues are not part of the Other Operating Revenues previously forecast in testimony this proceeding.

The Settlement was conducted and timely filed in accordance with Article 13.5 of the Commission's Rules of Practice and Procedure. WMA, SCE and TURN were the only parties that actively addressed this issue. No other

parties opposed the Settlement. The Settlement is reasonable, consistent with law, and in the public interest. It is approved.

26. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with § 311(d) of the Pub. Util. Code and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on or before February 6, 2006, and reply comments were filed on or before February 14, 2006.

To the extent that the comments merely reargued the parties' positions taken in their briefs, those comments have not been given any weight. The comments which focused on factual, legal or technical errors have been considered, and appropriate changes have been made.

27. Assignment of Proceeding

Geoffrey F. Brown is the Assigned Commissioner and David K. Fukutome is the assigned ALJ in this proceeding.

Findings of Fact

1. With respect to individual uncontested issues in this proceeding, unless otherwise stated in this opinion, SCE has made a *prima facie* just and reasonable showing.

2. SCE has substantially recovered from the financial effects of the 2000-2001 energy crisis, and it is not necessary to consider further financial recovery in resolving specific issues in this proceeding.

3. The concept of SCE's distribution infrastructure replacement program and its assertion that its workforce is aging are reasonable.

4. SCE has the burden to show that, under the circumstances of an aging distribution system and an aging workforce, its forecasts of costs are fully justified and supported.

5. SCE's nuclear related workforce is aging.

6. SCE did remove prior aging workforce costs from the recorded data prior to estimating and including test year 2006 aging workforce costs.

7. Since certain aspects of SCE's adjustment for its aging workforce are not fully explained or justified, it is reasonable to reduce the related request by 50%.

8. SCE's request to recover the used fuel transfer project incrementally to the three-year average of historic site projects is reasonable.

9. While certain NEI activities are related to reducing operating costs or improving plant performance, there are aspects of its advocacy of nuclear power that may not be appropriate for ratepayer funding.

10. Absent a showing that details the costs and benefits associated with participation in the NEI, TURN's recommendation to restrict ratepayer funding to 50% is reasonable.

11. SCE's request for a SONGS flexible outage schedule mechanism for the post-test years is reasonable.

12. For estimating the refueling outage core costs, SCE did not provide support for three adjustments: (1) a non labor escalation premium of $3,300,000, (2) a supplemental labor contract change of $750,000, and (3) a $3,800,000 credit due to a change in capitalization criteria. It is reasonable to exclude the non-labor escalation premium and the supplemental labor contract change for rate recovery. Since it is an accounting change only, it is reasonable to reflect the credit due to a change in capitalization criteria as proposed by SCE.

13. Due to uncertainties associated with the main generator rotor repair, it is reasonable to exclude it from the calculation of one-time activities associated with refueling outages.

14. SDG&E's methodology for calculating its SONGS related revenue requirement is reasonable.

15. SDG&E's showing on NRC DBT costs conforms to the specifications of D.04-12-015 and is reasonable.

16. SDG&E's share of DBT O&M and capital costs have exceeded the amounts initially estimated in A.02-12-028 and authorized in D.04-12-015.

17. Mohave shut down at the end of 2005.

18. Depending on the circumstances, the return to operation of Mohave may provide significant benefits to SCE's customers.

19. At this time, a temporary shutdown is the most appropriate ratemaking scenario for Mohave.

20. SCE's forecast of O&M expenses and capital related costs associated with the temporary shutdown of Mohave are reasonable.

21. The sale of Mohave sulfur credits will result in substantial revenues to SCE.

22. The future operating status of Mohave is unknown at this time, and consideration of the Coalition's Just Transition Plan is premature.

23. The amount of money at risk related to the anticipated 2008 outage at Four Corners does not justify establishing a new ratemaking mechanism for overhaul outages.

24. It is reasonable to spread the forecasted cost of the anticipated 2008 overhaul at Four Corners over three years to normalize the anticipated cost.

25. Regarding project development cost associated with proposed utility-owned generation opportunities, SCE should be subject to the same cost recovery risks as faced by independent producers.

26. SCE's proposed Project Development Division provides certain desirable support functions. It is reasonable to give SCE the opportunity to reflect such costs in rates.

27. For the purposes of this GRC, the August 13, 2005 MOU provides a reasonable basis for SCE and CPSD to address General Order 95 and 128 violation issues. It is reasonable for SCE and CPSD to continue to work out details for establishing and implementing the new maintenance program.

28. The August 29, 2005, SCE, DRA and TURN stipulation regarding the Priority 5 issue is reasonable, consistent with law and in the public interest.

29. SCE's current opportunity maintenance approach to Priority 5 maintenance is compliant with D.04-04-065.

30. It is reasonable for SCE to continue its current opportunity maintenance practice for correction of Priority 5 items until such time as the Commission authorizes a change in Priority 5 maintenance practices.

31. For Account 560.100, advanced technologies, it is reasonable to assume savings equal 50% of the costs, and to include the net cost of $2,050,000 for the test year.

32. For Account 562.100, SCE has provided sufficient information to justify its incremental aging workforce request related to five transmission system operators.

33. For Account 566.100, SCE's forecast related to training and safety relates primarily to employees hired because of increased workload and is reasonable.

34. For Account 566.300, SCE's proposed adjustment of $1,300,000 for additional office maintenance is reasonable. Due to uncertainties related to SCE's ITT support request, it is reasonable to reduce that portion of the request by $2,200,000, or 50%.

35. For Account 570.400, SCE's request of $2,682,000 for O&M associated with capital spending is the more reasonable than zero recommended by DRA.

36. For Account 570.400, SCE's request of $1,045,000 for substation life extension activities is not supported and excluded for rate recovery.

37. For Account 571.100 for poles and structures as well as Account 571.200 for insulators and conductors, it is more reasonable to spread the projected costs over nine rather than six years. It is also reasonable to exclude 25% of the life extension program cost estimate to account for potential double-counting of recorded costs as well as the possible inclusion of non-recurring costs.

38. For Account 580.100, advanced technologies, it is reasonable to assume savings equal 50% of the costs, and to include the net cost of $850,000 for the test year.

39. For the remaining portion of Account 580.100, SCE's use of a budget-based forecast to estimate distribution operations supervision & operations expense of $5,172,000 is reasonable.

40. For Account 580.200, vehicle fleet expenses, it is reasonable to use an average of SCE's and DRA's proposed increases in developing the test year forecast of $7,974,000.

41. SCE's request to increase RD&D spending by 259% is not supported. DRA's proposal to use an average of the last three recorded years is reasonable.

42. SCE's proposal to continue the one-way balancing account for RD&D is unopposed and reasonable.

43. For Account 583.400, pole inspections, DRA's proposal to normalize costs over the three GRC cycles is reasonable.

44. For Account 583.400, SAM inspections, DRA's recommendation to fund twice the number of inspections over 2003 is more reasonable than SCE's unsupported request for an approximate 400% increase.

45. For Account 586.100, turn on and off service, SCE's customer growth adjustment for labor expense is more reasonable than that proposed by TURN, since TURN's adjustment sets a 2003 base level that is less than the 2002 recorded level.

46. For Account 586.100, turn on and off service, TURN's use of customer growth plus 10% to derive non-labor costs is more reasonable than SCE's use of a three-year trend of data that is possibly distorted by the 2000 – 2001 energy crisis.

47. For Account 586.400, test or inspect meters, SCE did not provide sufficient information to justify its incremental aging workforce request related to six distribution meter technicians.

48. For Account 588.300, training, SCE did not provide sufficient information to justify its incremental aging workforce training request of $661,000. It is reasonable to assume that there are funds available in either the portion of the estimate based on the 2003 recorded amount of $21,997,000 or the $5,600,000 increase in 2004, to fund necessary and appropriate activities related to construction & maintenance accountant training, training evaluation and knowledge management, and software applications.

49. For Account 588.800, historic information demonstrates that work order write-offs are not primarily driven by customer growth. A four-year average of 2001 to 2004 recorded expenses is a reasonable method for estimating this account.

50. For Account 590.980, it is reasonable to adjust the TDBU overhead activity consistent with this decision's reductions to SCE's TDBU request.

51. For Account 593.300, supply expense, it is reasonable to assume that SCE's new way of handling materials is no less efficient than the old way.

52. For Account 597.400, repair billing meters, historically, the reprogramming of TOU meters has significantly affected the total level of expenditures, and it is reasonable to adjust this account to reflect SCE's estimate that there will be no such reprogramming during this GRC cycle.

53. For Account 456.900, added facilities, a five-year average of historic data from 2000 to 2004 is a reasonable method for calculating the test year expense.

54. The agreement between SCE and TURN regarding an audit of SCE's compliance with the requirements of D.99-09-070, which adopted SCE's Gross Revenue Sharing Mechanism for revenues received from its non-tariffed products and services, is reasonable.

55. For Account 902, non-labor meter reading expenses, SCE's requested 15% increase over 2003 levels is reasonable considering increases over the 1999 to 2003 historic period.

56. For Account 903.200, non-labor credit expenses, DRA's customer growth methodology is more reasonable than SCE's use of a three-year trend that includes data, which appears to have been affected by the 2000 – 2001 energy crises.

57. For Account 903.500, non-labor billing expenses, DRA's customer growth methodology is more reasonable than SCE's use of a three-year trend that includes data, which appears to have been affected by the 2000 – 2001 energy crises.

58. For Account 903.800, non-labor call center expenses, SCE's requested 4% decrease over 2003 levels is reasonable considering the moderate increases over the 1999 to 2003 historic period.

59. It is reasonable to reflect the Postal Service Board of Governors' November 14, 2005, approval of a postage rate increase, effective January 8, 2006, in the calculation of the forecasted test year postage expense.

60. For Account 903.900, information technology application services, given our concerns with data affected by the 2000-2001 energy crisis, lack of quantification of regulatory impacts, and productivity, DRA's use of a customer growth methodology to estimate both labor and non-labor expenses is more reasonable than SCE's use of a trend of 2001 - 2003 recorded data.

61. For Account 904, uncollectible expenses, Aglet's use of an average of 2002 and 2003 recorded information to develop the uncollectible factor, before adjustments, is a reasonable methodology to reflect the constant decline in the uncollectible factor from 1999 to 2003.

62. For Account 905.900, residential services and outreach, SCE's request for $464,000 to help it more effectively provide basic customer service to residential customers is reasonable.

63. For Account 905.900, customer process based satisfaction survey, SCE has not demonstrated the need to conduct its proposed new survey, estimated to cost $431,000.

64. For Account 905.900, internet improvements, while SCE does not fully support its request, it is reasonable to include 50%, or $200,000, to recognize the value to customers of expanded website capabilities.

65. Since DA-related costs in Accounts 901, 902 and 903 are no longer tracked separately, the forecast of those DA-related costs are embedded in SCE's forecasts for all customers. Forecasting separate DA-related costs is not appropriate at this time, due to the uncertainties associated with such estimates.

66. For Account 456, direct access fees, TURN's proposal to update the DA service fees to reflect inflation from 1999 to 2006 is reasonable.

67. For Account 908, government and mid-size business services, since SCE's proposed program appears to be replacing what SCE has done in the past, it is reasonable to reduce SCE's request by 50%, or $256,000 to reflect embedded costs.

68. For Account 908, customer process based satisfaction survey, SCE has not demonstrated the need to conduct its proposed new survey, estimated to cost $432,000.

69. For Account 908, internet improvements, while SCE does not fully support its request, it is reasonable to include 50%, or $200,000, to recognize the value to customers of expanded website capabilities.

70. For Account 908, billing and payment, SCE has not provided sufficient support to include the associated program costs of $311,000 in rates.

71. Consistent with D.05-09-018, it is reasonable to continue the EB&D program with full ratepayer funding.

72. The evidence does not support a 38% growth in Energy Center expenses from recorded year 2003 to test year 2006. It is reasonable to base the test year expenses on the 2003 recorded year amount.

73. DRA's proposal to cap increases for service charges at 25% above current levels is reasonable.

74. The service guarantee program is an important and effective tool for SCE to demonstrate to its customers that it is serious about its commitments and has a positive effect in maintaining or improving SCE's current level of customer service.

75. It is reasonable for ratepayers to pay for the labor and non-labor associated with the service guarantee program and for shareholders to pay for payments to customers.

76. SCE has investigated the customer satisfaction and the injury & illness recordkeeping problems, has taken actions it believes are appropriate, and has reported its efforts to the Commission's CSPD. CPSD's investigation of the matter is ongoing.

77. It is important to properly align and assign the benefits and costs of results sharing between ratepayers and shareholders.

78. Based on the design of SCE's results sharing proposal, it is reasonable to assign 50% of the costs to ratepayers and 50% to shareholders.

79. Inclusion of Spot Bonuses in the Total Compensation Study would result in SCE being, at worst, within 1.9% of market.

80. Since the new system for evaluating and awarding Spot Bonuses was implemented in November 2004, while the embedded recorded data used by SCE for forecasting test year costs is for the year 2003, the appropriate level that should be funded by ratepayers in the test year has not reasonably been established.

81. On a forward looking basis, the tracking system appears to be essential in substantiating how and why spot bonuses are awarded to employees.

82. Since the Cross Training Leadership and Executive Leadership Program provide some benefit to ratepayers, assigning 50% of the costs to ratepayers and 50% to shareholders is reasonable.

83. SCE has not requested double funding of its cross training program.

84. For Account 920/921, HR client services, SCE has provided sufficient information to justify its request for funding related to expansion of it OD/OCM activities.

85. The performance goals of the Executive Incentive Compensation Plan are comparable to those used for results sharing. Absent specific information on how executive incentive compensation is structured and calculated, it is reasonable to assume it is similar to that for results sharing and similarly allocate 50% of the costs to ratepayers and 50% to shareholders.

86. The Total Compensation Study does not specify or differentiate between ratepayer and shareholder funding for either comparator company compensation or SCE compensation.

87. For forecasting the executive compensation costs in Account 920/921, other than for the Executive Incentive Compensation Plan, it is reasonable to use an average of 2002 and 2003 data, which is reflective of current executive officer levels and salaries and excludes reduced non labor costs related to the energy crisis.

88. For Account 920/921, equal opportunity, due to uncertainties as to whether costs will return to pre-energy crisis levels and, if so, how fast that will occur, the five-year average used by DRA, which results in a test year estimate of $1,352,000, and provides an increase of $262,000 over the 2003 recorded level is reasonable.

89. For Account 920/921, in house legal resources, SCE has justified the continuation of 2003 costs, related to the documents and records management software purchase and the Whiteboard filing Tracking System, into the test year. However, continuation of $459,000 in non-labor test year expenses for computer and outside consulting services is not supported by the record.

90. There is insufficient information to justify a time tracking system for SCE's in-house counsel, but there is good reason to require additional data on the costs and benefits of such a system in SCE's next GRC.

91. For Account 920/921, regulatory policy and affairs labor, the addition of nine FTEs reasonably reflects a continuation of some vacancies and a potential lessening of workload due to some proceedings reflected in 2003 recorded data closing before and during the test year. DRA's adjustment to remove labor expenses associated with the Washington, D.C. Office is not supported by the record.

92. For Account 920/921, environmental health and safety non-labor, SCE reasonably explains that most of the increase in 2003 over 2002 was related to a $456,000 reduction in the 2002 EMF budget, which was restored in 2003.

93. For Account 920/921, public affairs, while the 2004 time-tracking study used by SCE is more comprehensive than the 2003 pilot study relied on by DRA, whether it is appropriate to apply 2004 time-tracking study results to the 2003 recorded expenses to obtain the differentiation between 2003 expenses that are properly charged to ratepayers and the 2003 expenses that are properly charged to shareholders is questionable.

94. For public affairs, while it is reasonable to include the FTE positions that have been filled in 2003 and 2004, SCE has not justified five new positions proposed for 2006.

95. For Account 920/921, energy supply & management labor expense, in order to properly calculate the average salary for 2003, the total labor expense should be divided by the average number of employees for the year.

96. For Account 920/921, QF resources labor, DRA's assumption that the overall net labor cost will be the average salary in 2003 applied to the expected number of employees in 2006 is reasonable.

97. For Account 920/921, reimbursable expenses, it is reasonable to exclude costs related to eight missing expense reports.

98. SCE has agreed to perform a review of all reimbursable expense reports for each employee included in SCE's GO 77-L submittal, whose annual total reimbursable expenses are $25,000 or more for any of the years 2004, 2005 and 2006. To cover the approximate 90% of the remaining reimbursable expenses, SCE it is necessary for SCE to also conduct another statistical study for recorded 2006 reimbursable expenses, for the remaining employees whose annual reimbursable expenses are less than $25,000, similar to that performed for 2003 recorded reimbursable expenses.

99. In proposing its adjustment for recognition awards in this proceeding, DRA did not provide any information or argument that would lead us to conclude that our discussion in the last GRC on this topic should now be disregarded.

100. In this proceeding, SCE has not shown that ratepayers benefit from SCE's decisions to diversify into non-regulated activities.

101. For Account 923, HR consulting expenses, it is reasonable to reflect the cost of benchmarking studies used to demonstrate the reasonableness of total compensation.

102. For Accounts 923 and 928, law & regulatory expenses, it is reasonable to exclude recorded data affected by the energy crisis for forecasting purposes.

103. For Account 928, law & regulatory, it is reasonable to include recorded expenses related to the Gas Border Price Investigation in forecasting test year costs.

104. For Account 923, environmental health and safety non-labor expense, while SCE's proposed budgeted costs for discrete consultant activities are reasonable, SCE did not justify the continuation of 2003 recorded costs into the test year.

105. For Account 923, ES&M consultant expenses, since SCE has not justified its ES&M consultant budget request, it is reasonable to instead use the 2003 recorded amount of $2,607,000 as the test year estimate.

106. For Account 923, QF resources consultant expenses, since SCE has not supported its $224,000 incremental request, it is reasonable to use the last recorded year as the test year forecast.

107. For Account 925, workers' compensation staff, SCE reasonably supports its test year estimate of $6,319,000, which is lower than the 2003 recorded amount of $7,324,000 but higher than the approximate unadjusted 2004 recorded amount of $5,700,000.

108. For Account 925, to forecast workers' compensation reserve, it is reasonable to use an average of 2001 and 2002 recorded data, since 2003 recorded costs do not appear to be representative of test year costs and the two-year average is not materially different from the 2004 recorded amount.

109. For Account 925, environmental health and safety, corporate safety, since SCE's budget based methodology does not consider possible cost reductions either for recorded activities that may be replaced by new programs or productivity improvements that may reduce existing costs, it is reasonable to assume that $226,000 in labor expense budgeted to improve SCE's ability to track

safety performance measures, if truly necessary, can be funded from that part of the unspecified budget that is based on the recorded 2003 expense level.

110. For Account 926, pension costs, it is reasonable to adopt DRA's proposed ERISA minimum funding proposal, as adjusted by SCE to reflect updated IRS information, since it is sufficiently conservative and in line with actuarial practice.

111. For Account 926, 401(k) savings plan costs, DRA indicates that it now agrees with SCE's calculations and no longer opposes SCE's forecast.

112. For Account 926 executive benefits, assuming no significant changes to the executive benefits and no changes in the number of eligible executives, it is reasonable to escalate the 2003 recorded amount of $11,157,000 to the test year level.

113. For Account 927, franchise fees, SCE's use of a weighted average for the three-year period, to develop a single franchise fee factor that, over the three-year rate case cycle, will provide recovery of anticipated franchise fees, including those related to franchise fee factor increases that will likely occur during 2006, is reasonable.

114. Utilization of MBE suppliers is highly dependent on the utilities' needs and the availability of MBE vendors to fulfill those needs.

115. SCE's previously stated goal of 22.5% for MBE suppliers was developed when utilities' were able to exclude certain services or products due to their specialized nature and lack of potential WMDVBE suppliers, and may no longer be realistic due to the Commission's elimination of exclusions in D.03-11-024.

116. SCE has achieved significant African American representation in its management through internal development and outside hiring; it has been less

successful for Latinos and Asian Americans whose population is larger than that of African Americans by six times and two times, respectively.

117. While philanthropy is an important consideration for SCE/EIX, the Commission has no jurisdiction over SCE's giving practices.

118. There is no evidentiary support for linking philanthropy and executive compensation.

119. Greenlining's proposal to link executive bonuses to supplier diversity and workforce diversity was not discussed in testimony or hearings. Substantiation and evidentiary support is lacking.

120. It would be speculative to attempt to quantify any ratepayer costs associated with Greenlining's assertion that ratepayers bear the cost of excessive executive compensation, particularly when unions take such compensation into account during bargaining with top management.

121. Transparency in reporting executive compensation is crucial when determining the reasonableness such as compensation.

122. TURN's request that the balance of funds collected for cost of removal related to non-ARO assets be recognized as a regulatory liability for ratemaking purposes is reasonable.

123. SCE separately accounts for non-ARO removal costs within FERC Account 108, Accumulated Provision for Depreciation, in accordance with regulatory accounting requirements, and has disclosed these costs in the audited financial statements filed with the Securities and Exchange Commission in accordance with financial reporting requirements.

124. Inflation is the primary reason for the significant increases in historic and projected costs of removal. Variations in assumed inflation over a plant asset's life can substantially affect the cost of removal accrual over that time period.

125. By the nature of the established cost of removal methodology where SCE is paying off current removal costs, while rates are being collected to fund future costs that are much higher than current costs, the non-ARO balance, which is already over $2 billion, will continue to grow.

126. It is reasonable to take a conservative approach in adjusting net salvage ratios, rates or accruals.

127. Except for Accounts 364 and 369, it is reasonable to use DRA's recommended net salvage rates based on the 15-year historical average.

128. Using SCE's proposed net salvage rate for distribution poles included in Account 364, the company would not accumulate sufficient funds to retire the existing poles, even if the removal costs remained at recent recorded levels, unadjusted for inflation over the remaining lives of the existing poles.

129. For Account 364, it is reasonable to use SCE's proposed compromise net salvage rate of -190%.

130. For Account 369, it is reasonable to use DRA's recommendation to cap the net salvage rate at -75%.

131. There is insufficient evidence to support the adoption of TURN's net present value methodology for determining costs of removal.

132. By the PTYR mechanism adopted by D.04-07-022, SCE was authorized plant additions for 2004 and 2005 based on its proposed budgets for those years, as presented in its 2003 GRC.

133. Pursuant to D.04-07-022, SCE filed Advice Letter 1808-E that established the CAAM for 2004-2005 to track the difference between actual (recorded) and authorized total company 2004-2005 gross capital additions plus cost of removal amounts. If, by the end of 2005, SCE fully implemented its 2004-2005 capital spending budget that was adopted in D.04-07-022 no customer refunds will be

required. However, if SCE's authorized capital additions are greater than its recorded capital additions over the entire two-year period, an overcollection in revenue requirement will be recorded in the CAAM and this amount will be returned to customers.

134. In projecting the test year 2006 plant balances for this GRC, it would be reasonable to consider the results of SCE's 2006 CAAM filing as it relates to both 2004 and 2005 recorded plant additions.

135. Since SCE's proposed capital project completion dates for the test year result in an equivalent 41.16% weighting percentage, which is consistent with historical weighting percentages, it is reasonable to use SCE's proposed completion dates for adopted test year projects.

136. In calculating the AFUDC rate, it is reasonable to use the amount of short-term debt available for construction, rather than the total amount of short-term debt financed by SCE, since the majority of short-term debt is used to fund balancing account under-collections and fuel inventory. The amount of short term debt available for construction in 2004 was $43,000,000, and is a reasonable amount to include in the calculation of the AFUDC rate for this proceeding.

137. It is reasonable to reflect allowances for costs transferred from CAC to CIAC on a forecast basis.

138. SCE's proxy approach for determining the maximum amount that ratepayers could have contributed during the ICIP period for the SONGS Used Fuel Storage and Marine Mitigation projects provides an objective basis for assigning costs that have been paid for by ratepayers.

139. The Florence Dam Buttress project that was completed in 2003 was a capital project and should never have been included in the expense forecast for the test year 2003 GRC.

140. For forecasting T&D meter set costs, due to potential productivity, it is reasonable to hold the 2004 recorded cost per meter of $2,922 constant through test year 2006.

141. In light of Resolution E-3921, TURN's suggestion to remove its issues regarding the calculation of line extension allowances in general, the exclusion of sub-transmission costs in the calculation of line extension allowances, and the utilities' data collection practices regarding line extension costs and projects, is reasonable.

142. Regarding line extension allowances for existing customers, SCE is in compliance with its current tariff language.

143. SCE's OOR forecast reasonably reflects revenues associated with forecasted costs of leased meters.

144. SCE's request for funding load growth projects in 2006 when the utilization is near or at 100% is reasonable.

145. For the wood pole replacement program, it is reasonable to use the average of the number of projected pole replacements for 2006, 2007 and 2008 in developing a normalized test year expenditure.

146. SCE's plan to replace 1857 mainline manual oil-filled switches at 300 switches per year, starting in 2006 is reasonable.

147. SCE has identified 131 mainline spring operated oil-filled switches with known problems and its plan to replace 15 per year from 2005 to 2008 is reasonable.

148. For spring operated oil filled switches, SCE has not provided a compelling reason to increase the number of replacements from 10 in 2005 to 85 in 2006.

149. It is reasonable to replace BURD switches over a six year period, at 162 switches per year, beginning in 2006.

150. For submersible fuse cabinets, it is reasonable to replace 125 cabinets per year over this GRC cycle.

151. Without more engineering data to justify SCE's plans, it is reasonable to limit the amount of underground primary cable replacement to 100 miles per year for this GRC cycle.

152. For ARs, it is reasonable to use an average of the recorded number of 2000, 2002, 2003 and 2004 replacements to forecast the number of test year replacements.

153. The use of the 2004 recorded number of capacitor bank replacements to forecast the test year level is reasonable.

154. Based on known problems, SCE has justified replacements planned for 52 vaults/manholes and 74 BURD structures from 2004 through 2008. SCE's belief that there may be other candidates beyond these amounts is insufficient to justify 22 additional test year replacements, which would more than double the test year expenditures.

155. Using an historic average is a reasonable method for forecasting the number of test year circuits to be remeditated.

156. The cost for a circuit remediation varies significantly from year to year and SCE's rough estimate of $1,000,000 per remediation appears reasonable.

157. For wood pole repairs, SCE has justified the number of poles that must be fiberglass wrapped and steel stubbed over the GRC cycle to comply with GO 95.

For ratemaking, it is reasonable to normalize the number of repairs over the three years.

158. It is reasonable to reflect SCE's modified forecasted bark beetle pole replacement costs of $3,500,000 in 2005 and $0 in 2006 in place of its original forecasted costs of $7,964,000 in 2005 and $3,318,000 in 2006.

159. For subtransmission wood pole replacements and repairs, the average cost per pole dropped to $14,197 per pole in 2004 due to work in rural areas. It is reasonable to reflect some work in rural areas in developing the test year cost per pole of $16,300.

160. For circuit automation, an average of 1999, 2000 and 2002 – 2004 historical expenditures, escalated to test year dollars, is a reasonable method for forecasting test year expenditures.

161. SCE has not justified its proposed increase in the distribution circuit breaker replacement program for 2006. It is reasonable to instead base the test year estimate on SCE's 2005 estimate, which is close to the recorded 2003 amount.

162. For A-Bank transformer replacements, the authorized 10 replacements per year would result in a replacement cycle close to the nominal design life.

163. For B-Bank transformer replacements, SCE has justified replacement of 13 transformers in the test year.

164. For distribution protection and control replacement, SCE has not provided sufficient information to justify replacing equipment at 25 substations for the test year. Base on recorded information, it is reasonable to provide funding for 21 substations at an average cost of $485,000 per substation.

165. SCE's cost estimates for the A/AA control room upgrades based on industry accepted standard engineering methods are, at this time, appropriate.

Since the spending pattern over the rate case cycle varies significantly, it is reasonable to normalize the expenditures by using an average of the forecasts.

166. For the substation equipment reactive replacement program, DRA's four year average is more appropriate, since SCE has not justified adding offset costs back into the blanket in determining its four-year average.

167. SCE has justified its request for cable trench cover replacement.

168. SCE has not provided sufficient information to support its proposed number of disconnect switch replacements.

169. SCE has sufficiently explained the basis for it proposed averaging of 1999 – 2002 data to forecast Rule 20B circuit breaker replacement costs.

170. For forecasting substation tools and grid dispatch, an average of the expenditures incurred during the post energy crisis years of 2002 and 2003 is reasonable.

171. For substation spare parts, since we have adopted SCE's capital request regarding B-Bank transformer replacements, it is reasonable to include SCE's estimate of the associated spare parts.

172. For the non-operational facility blanket, SCE has not explained why the proposed projects cannot be covered by the corporate real estate budget. SCE also did not explain why no money in this non-operational facility blanket has ever been spent.

173. Since there is no opposition to the Oak Valley project, it is reasonable to include the associated $500,000 in fee simple/rights-of-ways costs in 2006.

174. Nothing has changed regarding the Commission's reasoning for excluding fuel inventory from rate base, which included the cost to ratepayers, the balancing account treatment for fuel expenses and the low risk nature of fuel inventories.

175. The Commission's decision, in D.04-07-022, to include customer deposits as a rate base deduction is not sufficient reason to reconsider the current ratemaking policies for fuel inventory.

176. To forecast the test year M&S balance, it is reasonable to use the 2004 recorded balance of $131,419,000 and increase that amount by 3.3% per year, the average annual increase from 1999 to 2004.

177. To forecast the test year customer advances for construction balance, it is reasonable to use the 2004 recorded balance of $69,555,000 and increase that amount by cost escalation to the test year.

178. It is reasonable to include the entire forecasted weighted average customer deposit balance as an offset to rate base.

179. In light of the continuing upward trend in the recorded customer deposit balances, it is reasonable to use the 2004 recorded balance of $159,650,000 to forecast the test year amount.

180. The reserve for workers' compensation claims and the reserve for injuries and damages other than workers' compensation claims represent recorded liability accruals exceeding recorded payments.

181. The evidence does not support the proposition that ratepayers have provided the funds for the workers' compensation reserve.

182. It is reasonable to exclude atypical uncollectible accounts receivable for non-claims as an offset to working cash, since this particular uncollectible amount is not funded in rates.

183. Because of our commitment to the principles of SCE's distribution capital replacement program, it is reasonable to calculate the revenue requirement for the post test year period based on the adopted summary of earnings for 2006,

inflated operation and maintenance expenses, and increased capital related costs based on the addition of specific post test year plant additions to rate base.

184. Plant additions for 2006 have been fully scrutinized in this rate case. For the post test years, it is reasonable to assume a level of plant investment similar to that for the test year, with adjustments for inflation amounting to 2.5% for both 2007 and 2008.

185. DRA's request that the Commission extend the rate case cycle associated with SCE's test year request to four years is opposed by SCE and is contrary to the current rate case plan that allows major energy utilities the opportunity to file GRC applications every three years.

186. Regarding the CCIM, SDG&E's benchmarking study does not correctly reflect such factors as plant age, percentage of plant owned and acreage. Also SONGS 2 & 3 should be compared to costs of nuclear plant sites, not nuclear portfolios of other utilities. Possible commingling of O&M and capital costs and use of incremental plant additions rather than also considering costs of embedded plant also are concerns with the study.

187. In this GRC, there is only one issue related to SCE's forecasts for specific SONGS capital projects even though the forecasted expenditures are significantly higher than those experienced during the ICIP years.

188. The CCIM proposal to expense SONGS capital projects over one year increases the likelihood that SCE will not recover cost increases related to events, such as that of September 11, 2001, that are beyond SCE's control.

189. The CCIM proposal to reevaluate costs in the next GRC negates some of incentive for the utility to pursue cost savings and reduce costs.

190. It is reasonable to evaluate and set authorized levels of rate recovery for SONGS on a cost of service ratemaking basis.

191. The RIIM provides an incentive for SCE to perform authorized projects and activities related to distribution reliability and a means to credit money back to ratepayer if they do not do so.

192. At this time, it is reasonable to discontinue the use of a reliability incentive mechanism that is based on rewards and penalties.

193. Adoption of the RIIM is not a shift toward recorded cost ratemaking, but merely a means for SCE to meet its commitment to spend money for reliability purposes, to the extent that it is authorized.

194. SCE is not requesting additional funding for 600 additional linemen and groundmen because of the RIIM.

195. It is reasonable to assume that 600 additional linemen/groundmen can be accommodated within the revenue requirement authorized by this decision.

196. The November 2, 2005 SCE, CUE and TURN stipulation regarding the RIIM provides reasonable procedures to ensure authorized reliability –related projects and activities are undertaken and completed. The stipulation is consistent with law.

197. Although DRA proposes that reliability levels only be maintained and not improved, it has not provided any guidance as to what level of spending is necessary to do so.

198. The RIIM accomplishes the same goal as the RDAM in that it holds SCE accountable for distribution reliability related funds that it receives in rates. At this time, the RIIM is a fairer and more appropriate mechanism to address this aspect of distribution reliability.

199. Because there is a question, due to the reliability of certain SCE injury and illness data, of whether OSHA reportable injuries is an appropriate measure for

developing safety incentive, it is not reasonable at this time to continue the employee safety incentive mechanism.

200. The September 8, 2005 SCE, WMA and TURN settlement provides reasonable procedures for SCE to offer bill calculation services to submetered mobile home parks. The settlement is consistent with law and unopposed.

Conclusions of Law

1. Generation O&M expenses amounting to $442,170,000, as detailed in Appendix C, should be adopted for the test year.

2. For future requests for ratepayer funding of NEI dues, SCE should provide detailed descriptions of the activities, the associated costs, and the resulting company and ratepayer benefits associated with participation in that organization.

3. Amounts authorized by D.04-12-015 for SDG&E's SONGS Security Costs Balancing Account should no longer be subject to refund.

4. SCE should establish a two-way balancing account to record Mohave costs going forward.

5. At an appropriate time, after the permanent status of Mohave is determined, SCE should file an application seeking a final determination of the reasonableness of the costs recorded to the Mohave balancing account.

6. SCE should create a new Mohave Sulfur Credit Sub-Account in its ERRA tariff.

7. The issue of the distribution of revenues accumulated in the Mohave Sulfur Credit Sub-Account should be addressed when more information on the future operating status of Mohave is known.

8. For this GRC, SCE's request of $4,950,000 in expenses to fund its proposed PDD should be excluded from rates. However, SCE should be allowed rate

recovery of costs that support new generation and that are not associated with proposed projects. SCE should track such supportive project development costs in a memorandum account. Such costs can then be recovered in future rates to the extent that they are incurred, to the extent that SCE can justify their supportive nature, and to the extent that the total recorded PDD costs do not exceed SCE's forecasted amount.

9. In SCE's next GRC, PDD costs related to specific proposed projects should be excluded from the request.

10. SCE should seek cost recovery of generation related A&G expense and general plant overheads from DA customers in its ERRA proceedings.

11. Transmission O&M expenses amounting to $76,893,000, as detailed in Appendix C, should be adopted for the test year.

12. Distribution O&M expenses amounting to $350,420,000, as detailed in Appendix C, should be adopted for the test year.

13. The August 29, 2005 SCE, DRA and TURN stipulation regarding the Priority 5 issue should be approved.

14. SCE should continue its current opportunity maintenance practice for correction of Priority 5 items until such time as the Commission authorizes a change in Priority 5 maintenance practices.

15. In the next GRC, SCE should provide a detailed showing on the need and cost of the transmission life extension program (for poles and structures as well as insulators and conductors) that is include in Accounts 571.100 and 571.200. The showing should also demonstrate the incremental nature of the life extension program.

16. SCE's current one-way balancing account for RD&D should be continued.

17. Customer Accounts expenses amounting to $220,180,000 as detailed in Appendix C, should be adopted for the test year.

18. Customer Service and Information expenses amounting to $39,908,000, as detailed in Appendix C, should be adopted for the test year.

19. Administrative and General expenses amounting to $612,530,000, as detailed in Appendix C, should be adopted for the test year.

20. Until the current CPSD investigations regarding customer satisfaction and injury & illness recordkeeping problems are resolved, SCE should not use the data or information in question in determining results sharing goals and awards.

21. In its next GRC, SCE should provide detailed information on how its final results sharing goals were determined for the 2006 – 2008 period, what steps were taken to ensure the integrity of both the data and the process for making awards, and any further consequences or any required actions imposed by either SCE or the Commission, as a result of the Customer Satisfaction and Injury & Illness Recordkeeping investigations.

22. In its next GRC, SCE should provide a study on, or analysis of, a time-tracking system for its in-house counsel. It should include an estimated cost of performing this activity, any perceived benefits or detriments and any analysis related to the tracking system that was in place during the 1994 – 1998 timeframe.

23. In its next GRC, for the Public Affairs Department, SCE should redo the time-tracking study to reflect the areas of responsibilities requested for the test year and ensure that the results are appropriately applied to whatever methodology is used to forecast test year expenses.

24. For its next GRC, SCE should conduct another statistical study for recorded 2006 reimbursable expenses, for the employees whose annual

reimbursable expenses are less than $25,000, similar to that performed for 2003 recorded reimbursable expenses.

25. SCE should establish a two-way balancing account for pension costs, beginning with the 2006-2008 forecast period.

26. $225,000 in costs for complying with affiliate transaction rules should not be charged to ratepayers.

27. Changes to the Commission's specific goals for supplier diversity should be considered in the context of modifications to GO 156, on a generic basis, so that the views of all potentially affected parties can be considered.

28. As part of its next GRC filing, SCE should provide information on its workforce diversity achievements, similar to that provided by Greenlining in Exhibit 505.

29. For purposes of the General Order 77-L report, SCE should follow the PG&E model for reporting executive compensation.

30. In its next GRC, SCE should provide full transparent and understandable information on the present and future market value of the retirement severance benefits of its top executives.

31. Depreciation and amortization expense amounting to $793,387,000 as detailed in Appendix C, should be adopted for the test year.

32. In its next GRC, SCE should, as part of its account by account analysis for depreciation, analyze the effects of past inflation on its proposed cost of removal rates and justify the implicit inflation rates reflected in its proposed rates.

33. SCE should, as part of its account-by-account analysis for depreciation, provide analysis which quantifies potential accrual deficiencies for the future removal costs of existing assets. SCE should provide an analysis of what is causing any likely deficiencies.

34. SCE should establish a memorandum account to track the revenue requirement associated with its forecasted and recorded 2004/2005 plant additions. When plant additions are evaluated for the CAAM:

a. If SCE records plant additions at or in excess of $2,570,000,000 for the period 2004 – 2005, no further action is necessary.

b. If SCE records plant additions that are lower than $2,570,000,000 for the period 2004 – 2005, SCE should credit ratepayers with the excess revenue requirement collected through this decision, that is the difference between the revenue requirement associated with the 2004/2005 plant additions forecasted in this GRC and the revenue requirement associated with the recorded 2004/2005 plant additions. The credit should be calculated from the effective date of this decision.

35. The Florence Dam Buttress project should never have been included in the 2003 GRC expense forecast.

36. Before the costs for the Florence Dam Buttress project are included in future rates, SCE must provide convincing evidence that it did not benefit unduly by switching the project from expense to capital in 2003.

37. TURN's concerns regarding line extension allowances for existing customers should be brought up in conjunction with A.05-10-019.

38. DRA's request that the Commission extend the rate case cycle associated with SCE's test year request to four years should be denied.

39. SDG&E's request to establish the CCIM for SONGS should be denied.

40. Consideration of balancing account treatment for SDG&E's share of SONGS should be considered in the context of SDG&E's next general rate proceeding, where overall shareholder and ratepayer risks and benefits can be evaluated in a more cohesive manner.

41. Based on the results of this decision, the Settling Parties should jointly determine the levels of expenditures that will be subject to SCE's commitment to either spend the authorized amounts or credit ratepayers for the underspent amounts. When SCE files its compliance advice letter to submit the preliminary statement to establish the operation of the RIIM, it should include that jointly determined information, with supporting workpapers.

42. The November 2, 2005 SCE, CUE and TURN stipulation regarding the RIIM should be approved.

43. The employee safety incentive mechanism should be discontinued for the test year 2006 GRC cycle.

44. In its next GRC, SCE should report on its evaluation of the reliability of its injury and illness data and address its concern about whether OSHA recordable injuries should be used as the basis for an employee safety incentive mechanism. SCE should also provide information or data that demonstrates that, absent the incentive mechanism, the company has made, and will continue to make, employee safety a high priority during the full term of this GRC cycle.

45. The September 8, 2005 SCE, WMA and TURN settlement regarding bill calculation services for submetered mobile home parks should be approved.

O R D E R

IT IS ORDERED that:

1. Application (A.) 04-12-014 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.

2. 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.

3. Amounts authorized by Decision (D.) 04-12-015 for SDG&E's SONGS Security Costs Balancing Account should no longer be subject to refund.

4. San Diego Gas &Electric Company's (SDG&E) request that the amounts authorized by D.04-12-015 for its San Onofre Nuclear Generating Station (SONGS) Security Costs Balancing Account should no longer be subject to refund is granted.

5. Exhibit 900 is received in evidence.

6. SCE is authorized to implement its proposed revenue balancing account to adjust for sales variations and its proposed Post-Test Year Ratemaking (PTYR) mechanism for both 2004 and 2005 to the extent consistent with the foregoing discussion, findings of fact, and conclusions of law.

7. SCE shall establish a two way balancing to record the ongoing expenses and capital related costs associated with the Mohave Generating Station (Mohave).

8. At an appropriate time, after the permanent status of Mohave is determined, SCE shall file an application seeking a final determination of the reasonableness of the costs recorded to the Mohave balancing account.

9. The Petitions to Intervene filed by the Just Transition (Coalition) and the Navajo Nation are granted for the limited purpose of considering the Coalition's Motion for a "Just Transition" in Response to Closure of the Mohave Generating Station (Motion).

10. That part of the Coalition's Motion that requests creation of a new Mohave Sulfur Credit Sub-Account in SCE's Energy Resource Recovery Account tariff is granted. SCE shall establish that sub-account and separately track as a credit entry the revenues from the sales of SCE's sulfur credits created by Mohave's closure, effective December 31, 2005.

11. SCE shall not disburse funds from the Mohave Sulfur Credit Sub-Account without specific Commission authorization to do so.

12. That part of the Coalition's Motion that requests the Commission to expeditiously decide, as part of this consolidated proceeding, if and how proceeds from the sale of sulfur credits would be distributed to the Hopi Tribe and Navajo Nation is denied and shall be addressed elsewhere.

13. If there is a timely determination that Mohave will return to service, the issue of the distribution of revenues from the sale of Mohave sulfur credits shall be addressed as part of SCE's application to be filed in compliance with Ordering Paragraph 9 of D.04-12-016 and shall be litigated in that subsequent proceeding.

14. If Mohave is shut down or the resolution of Mohave's future operating status is delayed, SCE should file an application, no later than January 1, 2007, for authority to disburse funds accumulated in the Mohave sulfur credit sub-account along with a proposal for such disbursement.

15. SCE shall establish and implement appropriate procedures to satisfy our requirements as specified above in the conclusions of law related to the proposed Project Development Division.

16. In its next GRC, SCE shall submit the results of an audit of its compliance with the requirements of D.99-09-070 which adopted SCE's Gross Revenue Sharing Mechanism for revenues received from its non-tariffed products and services. As part of this audit, SCE shall review its determination and recording

of incremental and non-incremental costs related to non-tariffed products and services from the adoption of D.99-09-070 (September 1999) through the recorded base year for its next GRC.

17. SCE shall continue the service guarantee program as adopted in D.04-07-022.

18. The August 29, 2005 SCE, Division of Ratepayer Advocates (DRA) and The Utility Reform Network (TURN) stipulation regarding the Priority 5 issue is approved.

19. SCE shall continue its one-way balancing account for Research Development and Demonstration expenditures.

20. SCE shall establish a two-way balancing account for pension costs, beginning with the 2006-2008 forecast period. The balancing account shall record the difference between actual and forecast costs and should be amortized beginning in 2009. Any accumulated balance shall receive interest at the commercial paper rate, consistent with treatment of interest accruals for other SCE balancing accounts.

21. SCE shall establish a memorandum account to track the revenue requirement associated with its forecasted and recorded 2004 and 2005 plant additions. When plant additions are evaluated for the Capital Additions Adjustment Mechanism, SCE shall evaluate 2004 and 2005 recorded plant additions as described in the conclusions of law and credit ratepayers as necessary.

22. DRA's request that the Commission extend the rate case cycle associated with SCE's test year request to four years is denied.

23. SDG&E's request to establish the Cost Control Incentive Mechanism for SONGS is denied.

24. The November 2, 2005 SCE, California Utility Employees and TURN stipulation regarding the Reliability Investment Incentive Mechanism is approved.

25. SCE's employee safety incentive mechanism shall be discontinued for the test year 2006 general rate case (GRC) cycle. In its next GRC, SCE shall provide information or measurable data to demonstrate that, absent such mechanism, employee safety has been and will continue to be a high priority over the entire general rate case cycle.

26. In its next GRC, SCE shall report on the evaluation of its injury and illness data and address concerns regarding the use of Occupational Safety and Health Administration recordable injuries as the basis for an employee safety incentive mechanism.

27. The September 8, 2005 SCE, Western Manufactured Housing Community Association and TURN settlement regarding bill calculation services for submetered mobile home parks is approved.

28. Application 04-12-014 and Investigation 05-05-024 are closed.

This order is effective today.

Dated _____, at San Francisco, California.

APPENDIX A
List of Appearances

Applicant: James M. Lehrer, Frank A. McNulty, Megan Scott-Kakures and Sumner J. Koch, Attorneys at Law, and Russell G. Worden and Bruce Foster, for Southern California Edison Company.

Interested Parties: Angela S. Beehler, for Wal-Mart Stores, Inc., Sam Walton Development Complex; William H. Booth, Attorney at Law, for California Large Energy Consumers Association; McCracken, Byers & Haesloop, by David J. Byers, Attorney at Law, for California City-County Street Light Association; Carrie Camarena, Deputy General Counsel, for the Greenlining Institute; Elizabeth A. Collier, Attorney at Law, for Pacific Gas & Electric Company; Goodin, MacBride, Squeri, Ritchie & Day, LLP, by Brian T. Cragg, Attorney at Law, for Independent Energy Producers Association and by James D. Squeri, Attorney at Law, for California Retailers Association and California Building Industry Association; Douglas & Liddell, by Daniel W. Douglass, Attorney at Law, for Direct Access Customer Coalition and Western Power Trading Forum and by Gregory S. G. Klatt, Attorney at Law, for Alliance for Retail Energy Markets; Department of the Navy, by Norman J. Furuta, Attorney at Law, for Federal Executive Agencies; Morrison & Foerster, LLP, by Peter Hanschen, Attorney at Law, for Agricultural Energy Consumers Association; Marcel Hawiger, and Nina Suetake, Attorneys at Law, for The Utility Reform Network; Manatt, Phelps & Phillips, LLP, by David L. Huard, Attorney at Law, for Catholic Healthcare West, by Randall W. Keen, Attorney at Law, for Lowe's Home Improvement, and by Margaret E. Snow, for County of Los Angeles; Adams, Broadwell, Joseph & Cardozo, by Marc D. Joseph, Attorney at Law, for Coalition of California Utility Employees; Alcanter & Kahl, by Evelyn Kahl, Attorney at Law, for Energy Producers and Users Coalition and by Nora E. Sheriff, Attorney at Law, for Cogeneration Association of California; Sutherland, Asbill & Brennan, LLP, by Keith R. McCrea, Attorney at Law, for California Manufacturers & Technology Association; Andersen & Poole, by Edward G. Poole, Attorney at Law, for Western Manufactured Housing Communities Association; JBS Energy, by Gayatri Schilberg, for The Utility Reform Network; Laura J. Tudisco, Paul Angelopulo, Gregory Heiden, and Nicholas Sher, Attorneys at Law, for Office of Ratepayer Advocates; James T. Walsh and Glen J. Sullivan, Attorneys at Law, and Ronald Vanderleeden, for San Diego Gas & Electric Company; James Weil, Director, for Aglet Consumer Alliance.

State Service: Mark Bumgardner, Martin G. Lyons and Robert M. Pocta, for Division of Ratepayer Advocates; Donald J. LaFrenz and Laura Lei Strain, for the Energy Division.

(END OF APPENDIX A)

APPENDIX B
List of Acronyms and Abbreviations

A. - Application

AB – Assembly Bill

A&G – Administrative and General

ACMI – Average Customer Minutes of Interruption

AFUDC – Allowance for Funds Used During Construction

Aglet – Aglet Consumer Alliance

ALJ – Administrative Law Judge

AR – Automatic Recloser

AReM – Alliance for Retail Energy Markets

ARO – Asset Retirement Obligation

BOON – Best Option Outside Negotiation

BOR – Board of Review

BURD – Buried Underground Residential Distribution

CAAM – Capital Additions Adjustment Mechanism

CAC – Customer Advances for Construction

CARE – California Alternate Rates for Energy

CEC – California Energy Commission

CIAC – Contributions In Aid of Construction

CPI – Customer Price Index

CPM – Cost Per Meter

CPSD – Consumer Protection and Safety Division

CRE – Corporate Real Estate

CS&I – Customer Service and Information

CSBU – Customer Service Business Unit

CTC – Competition Transition Charge

CUE – Coalition of California Utility Employees

D. – Decision

DA – Direct Access

DBT – Design Basis Threat

DACC – Direct Access Customer Coalition

DACRS – Direct Access Cost Responsibility Surcharge

DRA – Division of Ratepayer Advocates

E&BD – Economic and Business Development

ECAC – Energy Cost Adjustment Clause

EDR – Economic Development Rate

EH&S – Environmental Health and Safety

EIP – Executive Incentive Compensation Plan

EIX – Edison International

ERISA – Employee Retirement Income Security Act

ERRA – Energy Resources Recovery Account

ES&M – Energy Supply and Management

FASB – Financial Accounting Standards Board

FERA – Family Energy Rate Assistance

FERC – Federal Energy Regulatory Commission

FTEs – Full Time Equivalents

FFO – Funds From Operations

Four Corners – Four Corners Generating Station

FTEs - Full Time Equivalents

GRC – General Rate Case

Greenlining – Greenlining Institute

HMWD-PE – High Molecular Weight Polyethylene

HP – Health Physics

HR – Human Resources

Hydro – Hydroelectric

I. - Investigation

ICIP – Incremental Cost Incentive Program

IEPA – Independent Energy Producers Association

IMM – Interdepartmental Market Mechanism

INPO – Institute of Nuclear Power Operations

IT – Information Technology

M&S – Materials and Supplies

MBE – Minority Business Enterprise

MHP – Mobile Home Park

MIP – Management Incentive Program

Mohave – Mohave Generating Station

Moody's – Moody's Investor Services

MOU – Memorandum of Understanding

NARUC - National Association of Regulatory Utility Commissioners

NEI – Nuclear Energy Institute

NRC – Nuclear Regulatory Commission

O&M – Operations and Maintenance

OCM – Organizational Change Management

OD – Organizational Development

OOR – Other Operating Revenue

ORA – Office of Ratepayer Advocates

P&B – Pensions and Benefits

PBOP - Post-Retirement Benefits Other Than Pensions

PBR – Performance-Based Ratemaking

PDD – Project Development Division

PG&E – Pacific Gas and Electric Company

PHFU -- Plant Held for Future Use

PILC – Paper Insulated Lead Covered

PPA – Purchased Power Agreement

PROACT – Procurement Related Obligations Account

PTY – Post-Test Year

PTYR – Post-Test Year Ratemaking

PX – Power Exchange

QF – Qualifying Facility

RD&D – Research Development and Demonstration

RDAM – Reliable Distribution Accountability Mechanism

RIIM – Reliability Investment Incentive Mechanism

SAM – Structural Analysis Methodology

SCE – Southern California Edison Company

SDG&E – San Diego Gas & Electric Company

SFAS – Statement of Financial Accounting Standard

SIRP – Substation Infrastructure Replacement Program

SoCalGas – Southern California Gas Company

SONGS – San Onofre Nuclear Generating Station

T&D – Transmission and Distribution

TDBU – Transmission and Distribution Business Unit

TRMC – Transformer Resource Management Committee

TURN – The Utility Reform Network

WMA – Western Manufactured Housing Community Association

WMDVBE – Women, Minority and Disabled Veterans Business Enterprise

WPTF – Western Power Trading Forum

(END OF APPENDIX B)