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Decision 96-01-011 January 10, 1996

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for Authority to Increase Its Authorized Level of Base Rate Revenue under the Electric Revenue Adjustment Mechanism for Service Rendered Beginning January 1, 1995 and to Reflect this Increase in Rates.	Application 93-12-025 (Filed December 27, 1993)
Order Instituting Investigation into the Rates, Charges, and Practices of SOUTHERN CALIFORNIA EDISON COMPANY, Establishment of the Utility's Revenue Requirement, and Attrition Request.	I.94-02-002 (Filed February 3, 1994)

(See D.94-12-045 for appearances.)

(Additional Appearances)

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Glynnis Jones and Pete Price, for Appliance Recycling Centers of America, Inc.; Marc Joseph, Attorney at Law, for IBEW Local 47, UWUA Local 246; Steven Kotz, Attorney at Law, for California Cogeneration Council; and Sara Steck Myers, Attorney at Law, for the Center for Energy Efficiency and Renewable Technologies; interested parties.

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OPINION ON SETTLEMENT AND PHASE 1 ISSUES

1. Summary

This decision addresses a settlement between Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), and the Division of Ratepayer Advocates (DRA) with respect to Phase 1 and Phase 3 of Edison's general rate case. In Phase 1, the Commission reviews Edison's results of operations and authorizes a base rate revenue requirement which is identified in Edison's tariffs as the Authorized Level of Base Rate Revenue (ALBRR). Phase 3 involves certain issues surrounding Edison's San Onofre Nuclear Generating Station (SONGS) Units 2&3.

In this decision, we reject the Phase 1 (ALBRR) portion of the settlement because we do not believe that it is reasonable in light of the whole record, consistent with the law, and in the public interest. Although we reject this portion of the settlement, the ALBRR that we adopt today is only $9.067 million less than that proposed in the settlement. What is different is the allocation of the ALBRR among different programs consistent with our public interest goals. Funding levels for certain programs were adjusted, based on the evidentiary record presented before us or, in some circumstances, where the funding of certain programs was not consistent with the law.

With regard to Phase 3, we believe resolution of the SONGS 2&3 issues is timely given the status of our electric industry restructuring proceeding (Rulemaking (R.) 94-04-031; Investigation (I.) 94-04-032). On key elements of the Phase 3 portion of the settlement, the only parties in support are Edison and SDG&E. This indicates that the settlement seems to lack the broad and continuing support which we would prefer in settlements that we adopt. Therefore, we take a cautious approach and treat the Phase 3 testimony supported by Edison and SDG&E as a joint proposal.

We find merit with Edison's and SDG&E's conceptual framework with regard to Phase 3 issues although we have concerns with particular aspects that we believe are inconsistent with the law and not in the public interest. We also note that portions are inconsistent with the general principles regarding stranded cost recovery that we recently have adopted in our restructuring proceeding (D.95-12-063). Therefore in this decision we adopt certain guidelines which modify the Edison and SDG&E proposal for SONGS 2&3 cost recovery. We will allow Edison and SDG&E 25 days to respond to the policy which we propose for SONGS. If they accept the utilities should submit a detailed proposal consistent with the policy which we adopt here. Other parties may comment on the utilities' filing no later than Febraury 20, 1996. If the utilities do not accept our SONGS policy, then we will resolve this issue either in a separate opinion in this rate case or in another appropriate proceeding.

Because the settlement was filed late in 1994, we could not review and approve or reject the settlement in time to have revised rates in effect on January 1, 1995, as called for in the rate case plan. Since the settling parties proposed a reduction in Edison's ALBRR, we issued Decision (D.) 94-12-045, our Interim Decision, which adopted the overall revenue requirement proposed by the settling parties on an interim basis, so that ratepayers would not be disadvantaged before future decisions issued.

Prior to the settlement being filed, we developed a complete evidentiary record (as well as full briefing) on Phase 1 issues. Therefore, even though this decision rejects the settlement, we still have a complete evidentiary record from which we determined the final ALBRR for Phase 1.

This decision adopts an ALBRR for the Edison general rate case of $3,839 million, which is $9.067 million less than the settling parties' ALBRR which we adopted in our Interim Decision.

The corresponding total ALBRR (which incorporates the impact of proceedings outside the general rate case) is $4,017 million (including a minor adjustment to the 1995 Cost of Capital rate increase to account for the lower rate base and net-to-gross multiplier adopted in today's decision). The adopted ALBRR is to be used to set base rates in Edison's current Energy Cost Adjustment Clause (ECAC) proceeding, Application (A.) 95-05-049. In the Interim Decision, we set the ALBRR subject to refund (i.e., we stated that a downward adjustment to the ALBRR in future decisions *may* be retroactive to January 1, 1995). However, the ALBRR we adopt today is prospective from January 20, 1996.

A major task in Phase 1 is determining Edison's appropriate test year revenue requirement. Some of the major issues are Edison's funding requests for demand side management (DSM); research, development, and demonstration (RD&D); total compensation; and health care costs. Other significant issues include Edison's request to increase certain customer service charges and attrition year increases.

2. Procedural Background

2.1 Edison's Application and 1994 Hearings

The procedural history in this proceeding is more lengthy than usual because the Commission had completed evidentiary as well as public participation hearings in the results of operations phase (Phase 1) of Edison's general rate case prior to Edison, SDG&E, and DRA tendering their settlement on both Phase 1 and Phase 3 issues.[1] Edison filed the application for its general rate case

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1 In response to DRA's motion to strike Edison's and SDG&E's rebuttal testimony regarding the cost-effectiveness and alternative pricing proposals for their nuclear power plants, the assigned ALJ established a separate phase of this general rate case (Phase 3) where the cost-effectiveness and alternative pricing

(Footnote continues on next page)

for test year 1995 on December 27, 1993. At that time, Edison requested an increase of approximately $117 million over the expected December 31, 1994 ALBRR for test year 1995. In addition, the company sought attrition year rate increases of $120.955 million beginning January 1, 1996, and $111.171 million beginning January 1, 1997. On July 21, 1994, after the conclusion of the evidentiary hearings, Edison modified its request to an increase of $76.414 million. On October 3, 1994, Edison again modified its request to reflect testimony in the September update hearings. Edison's final litigation position was a requested increase of $62.980 million, with attrition year increases of $92.1 million for 1996 and $96.8 million for 1997.

On February 3, 1994, the Commission instituted I.94-02-002 into the rates, charges, and practices of Edison. On February 4, 1994, the ALJ consolidated the investigation with the general rate case application as the procedural vehicle for considering recommendations which may go outside the scope of the application.

DRA addressed the utility's proposed results of operations, as well as many policy matters. In March 1994, DRA recommended a decrease of $313.5 million in Edison's ALBRR for test

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(Footnote continued from previous page) proposals for nuclear power plants raised by DRA in Exhibit 404 as well as in Edison's direct and Edison's and SDG&E's rebuttal testimony, could be properly considered. The Commission affirmed the ALJ's ruling in the Interim Decision, D.94-12-045, slip op. at pp. 3-4.

year 1995. DRA also recommended that the Commission not allow routine attrition year increases for Edison in 1996 and 1997. After the update hearings, DRA revised its recommended decrease for test year 1995 to a decrease of $160.1 million.

In addition to DRA, many other parties also actively participated in the 1994 evidentiary hearings or briefing.[2] The Commission held 43 days of evidentiary hearings between April 5 and July 11, 1994, covering the parties' initial evidentiary showings and rebuttal testimony.

Parties filed opening briefs on August 18, 1994 and reply briefs on September 1, 1994.[3] The Commission held update hearings on September 19, 1994, to incorporate the most recently available information on several topics.

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2 These parties include Advanced Photovoltaic Systems, Inc. (APS); Ascension Technology, Inc. (Ascension); Bechtel Corporation (Bechtel); California City-County Street Light Association (CAL-SLA); California Department of General Services (DGS); California Energy Commission (CEC); California Farm Bureau Federation (Farm Bureau); California Large Energy Consumers Association (CLECA); California/Nevada Community Action Association (Cal/Neva); California Solar Energy Industries Association (CSEI); California Trade & Commerce Agency (Trade and Commerce Agency); Cogeneration Association of California (CAC, which submitted some testimony under their former name, the Cogenerators of Southern California); Cogeneration Service Bureau (CSB); Federal Executive Agencies (FEA); Insulation Contractors Association (ICA); Local 47 of the International Brotherhood of Electrical Workers, AFL-CIO and Local 246 of the Utility Workers Union of America, AFL-CIO (Intervenor Unions); Natural Resources Defense Council (NRDC); Sacramento Municipal Utility District (SMUD); SDG&E; Solar Energy Industries Association (SEIA); South Coast Air Quality Management District (SCAQMD); Southern California Association of Governments (SCAG); Toward Utility Rate Normalization (TURN); Union of Concerned Scientists (UCS); United States Department of Energy (DOE); University of California (UC); Utility Photovoltaic Group (UPVG); and Western Mobilehome Parkowners Association (WMA).

3 TURN's unopposed motion for acceptance of late-filed findings of fact and conclusions of law, dated August 22, 1994, is granted.

2.2 Public Participation Hearings

The Commission held seven days of public participation hearings in nine southern California communities in April and May 1994. The Commission held these hearings prior to Edison, SDG&E, and DRA filing their joint motion for adoption of a settlement agreement. The Commission held hearings in Laguna Beach, Long Beach, Culver City, Palm Springs, Palm Desert, Ventura, Monrovia, Ontario, and Visalia.

The Commission held two additional public hearings in June 1994: (1) in Fullerton, California, for Edison employees and retired employees[4] and (2) in San Clemente, California, for public comment on DRA's proposal to deny Edison's request for operating funds to keep its nuclear plants in operation.

Hundreds of Edison customers, employees, and representatives of local organizations attended the hearings to express their views on a variety of issues. Because of the number of people attending the hearings, this decision cannot attempt to summarize each speaker's remarks. However, the principal issues addressed in these hearings include the following.

Many speakers commented that Edison's rates are, in general, too high. Specific segments of the population, such as senior citizens on a fixed income, expressed the difficulty of coping with an increasing utility bill on a fixed income. Also, agricultural users stated their rates were too high. Speakers in the Coachella Valley were particularly upset regarding the amount

4 The Commission held this hearing since in the past, there has been a high level of interest by union employees and retired employees to testify, and the Commission has had difficulty hearing from the employees as well as the general public in the limited time available for a public participation hearings.

of their bills, especially in the summer months, and urged, among other things, an increase in baseline as well as the initiation of a pilot program to provide special financing for DSM in this area. Other speakers stated Edison's rates were not excessive, and praised Edison's quality of service, especially during recent disasters such as the fires and earthquake. Several speakers stated Edison was not efficient.

Various city officials supported Edison's role in promoting DSM to cities because DSM assisted certain cities in meeting environmental regulations and in reducing their consumption of electricity. Several speakers urged the Commission to support Edison's efforts at economic development and business retention in California. Other speakers supported Edison's assistance to the community, particularly to schools and to nonprofit community organizations. Other speakers stated that they did not believe it was appropriate for Edison to spend money on philanthropic organizations at ratepayer expense.

Many speakers stated that they did not want ratepayer funds used to support Edison's research on electric vehicles.

A speaker addressed the issue of RD&D. Specifically, the speaker urged the Commission not to authorize ratepayer funds to support off-grid photovoltaic research, stating that such funding would promote unfair competition. The speaker, representing a small company doing off-grid photovoltaic work, stated that such funding will put him at a competitive disadvantage.

Various speakers stated that if the Commission approves a rate increase, that the rate increases for residences should not be greater than increases in other categories. Several speakers addressed and requested changes in Edison's rate and tariff schedules.

At several hearings, and particularly the public hearings in San Clemente and Laguna Beach, the speakers addressed Edison's nuclear plants and DRA's funding proposals. A number of speakers were opposed to closing SONGS. These speakers stated that the plant was safe and efficient, that plant closure would cost about 2,500 jobs, and would require more fossil fuel use and lead to degradation of air quality. These speakers also spoke of the environmental benefits of nuclear power. Other speakers spoke of the community support Edison, through SONGS, provided to schools and other community organizations.

Numerous other speakers stated that SONGS should be closed because of the dangers of nuclear power, the plant's threat to health and environment, and the high cost of disposing of nuclear waste. These speakers argued that the ratepayer costs were too high because of the continued operation of SONGS, and that skilled workers at the plant can be retained or retrained in other areas.

Union employees stated that the Commission should not cut Edison's request for funding for employee compensation which is the product of collective bargaining agreements. They stated that Edison provides a high level of service, especially after natural disasters such as the earthquake, and that market standards cannot be applied to wages because the experience level of the working force at Edison is a benefit to ratepayers. Finally, although we did not hold public participation hearings regarding the settlement, we did receive many letters addressing the settlement.

We express our appreciation to all of the individuals who took the time to attend public participation hearings in this proceeding or to write us with their comments. The main issues raised in the public participation hearings are addressed in this decision, with the following exceptions. Nuclear safety issues were not raised by any party in this proceeding and are not before us. Questions regarding tariffs and rates, such as baseline rates, are cost allocation issues. We consider these type of issues in Phase 2 of this general rate case, which is addressed in a separate

Commission decision.[5] The Commission is also conducting a separate proceeding regarding low emission vehicles and will address such issues in that proceeding. (See I.91-10-029/ R.91-10-028.)

2.3 The Settlement

On September 6, 1994, at a prehearing conference (PHC) which was intended to schedule hearings on Phase 3 issues, Edison and DRA orally advised the Commission that they had reached a memorandum of understanding intended to serve as the basis for a settlement agreement resolving the contested issues between Edison and DRA in Phases 1 and 3 of Edison's general rate case.

On September 8, Edison and DRA filed a joint motion requesting that the Commission waive the requirements of Rule 51.2 of the Commission's Rules of Practice and Procedure that a settlement be filed with the Commission within 30 days of the last day of hearing and consider the parties' settlement agreement.

5 In addition to baseline rate issues, speakers from the Coachella Valley requested a pilot program to provide special funding for DSM in their area. On June 22, 1994, in another proceeding, the Commission issued D.94-06-048, approving a pilot energy efficiency program for Edison to assist residential customers in improving the energy efficiency of their homes. This pilot program applies to the Coachella Valley and the community of Leisure World in Laguna Hills.

Edison and DRA presented their memorandum of understanding, but not the settlement with the motion.[6]

On October 5, 1994, the Assigned Commissioner, President Fessler, issued a ruling (the Ruling) addressing the joint motion. The Ruling, among other things, granted Edison's and DRA's request for a waiver of the requirements of Rule 51.2 so that a proposal to adopt a settlement might be filed later than 30 days after the last day of hearing. Because the proposed settlement would be filed too late for the Commission to fully review it and to issue a final Commission decision in Phase 1 by the end of the year, the Ruling also suspended the rate case plan regarding a commitment to issue a proposed and final Commission decision in Phase 1 by the end of the year. However, the Ruling stated that the Commission would consider a proposed decision before the end of the year which would adopt an interim ALBRR until a final Commission decision is issued. The Commission issued the Interim Decision on December 21, 1994.

On November 16, 1994, Edison, SDG&E, and DRA (settling parties) filed a Joint Motion for Adoption of Settlement Agreement, together with the settlement agreement and a joint comparison exhibit (Joint Motion). The settling parties served testimony supporting the settlement agreement on December 19, 1994. Because hearings on the settlement agreement would be necessary, at the very least to receive the settling parties' additional testimony, the ALJ determined that requiring parties to file comments as well as testimony objecting to the settlement agreement may be redundant. In a December 9, 1994 ruling, the ALJ waived the comment requirements of Rule 51.4 and directed nonsettling parties to serve their testimony regarding the settlement agreement no later than February 14, 1995. Other than the settling parties, the

6 Although Edison and DRA originally indicated their intent to file the settlement on October 13, 1994, they tendered the settlement to the Commission's Docket Office for filing on November 16, 1994.

following parties served testimony or filed briefs: CAL-SLA; CEC; DGS; Farm Bureau; NRDC; Southern California Gas Company (SoCalGas); and TURN (on Phase 1 issues) and California Cogeneration Council (CCC); Center for Energy Efficiency and Renewable Technologies (CEERT); CLECA; California Manufacturers Association (CMA) and Industrial Users (IU) (jointly); Independent Energy Producers Association (IEP); Intervenor Unions; and TURN (on Phase 3 issues).[7]

On March 3, 1995, DRA informed the ALJ by letter that it became aware of "new factual" information submitted to the Commission by Edison in other dockets, and under PU Code 583 protection of confidentiality, that contradicts the information relied upon by DRA in entering the settlement, and unless renegotiation is initiated based on the new factual information, DRA will have no other option than to withdraw its support as a settling party. (DRA March 3 letter at p. 1.) The issue of DRA's right to withdraw from the settlement agreement was the subject of three PHCs on March 8, March 17, and March 21. At the March 21 PHC, the settling parties agreed to proceed in support of the settlement agreement with a limited waiver of Section 6.1 of the settlement agreement[8] to allow DRA to introduce additional testimony regarding (a) a different Incremental Cost Incentive Pricing (ICIP) level and (b) the cost-effectiveness of running SONGS. TURN also submitted testimony, and parties had an opportunity to rebut DRA and TURN. In order to accommodate DRA's need for additional time to prepare its testimony, hearings and briefing on the settlement agreement were bifurcated. Hearings on the Phase 1 issues were held from April 3 through April 11, and

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7 The Appliance Recycling Centers of America, Inc. (ARCA) also served testimony, but withdrew this testimony prior to hearings because it had substantially resolved its issues with Edison.

8 Section 6.1 of the settlement agreement provides in pertinent part that the settling parties should jointly request that the Commission approve the settlement agreement without change.

hearings on the Phase 3 issues were held from May 15 through May 24. The matter was submitted on June 16, 1995 after the parties filed reply briefs on the Phase 3 portion of the settlement.

In D.94-12-045, the Interim Decision, we adopted an ALBRR to set 1995 base rates. We set the ALBRR subject to refund and stated that it was "subject to refund in the event the Commission makes a further downward adjustment to the ALBRR in future decisions. Any increase to the ALBRR in future Commission decisions shall be prospective only." (D.94-12-045, slip op. at p. 14, Ordering Paragraph 3.)

3. Commission Review of the Settlement

3.1 Settlement Terms

The settlement resolves Phase 1 and Phase 3 issues in this general rate case. With respect to the Phase 1 issues, the settling parties agree that Edison's revenue requirement should be reduced by $67.3 million below the year-end 1994 ALBRR of $3,915 million, resulting in a 1995 ALBRR of approximately $3,848 million.[9] These reductions primarily result from reductions in Edison's DSM and RD&D expenses ($84 million and $24 million respectively from Edison's position at the close of evidentiary hearings) and an increase in certain customer service charges.

The settlement also addresses Phase 3 issues which relate to SONGS 2&3.[10] The settlement terms regarding SONGS 2&3 are quite complex. Some key provisions are:

- o Accelerate recovery of SONGS 2&3 sunk costs. As of February 1, 1996, Edison and

9 This figure does not include the impact of Edison's 1994 cost of capital proceeding.

10 SONGS 2&3 are pressurized water reactor nuclear generating units which each have an output rating of 1127 megawatts electric and have been in commercial operation since 1983 and 1984 respectively. Edison owns a 75.05% share of SONGS 2&3, SDG&E owns a 20% share and the cities of Anaheim and Riverside own 3.16% and 1.79% shares respectively.

SDG&E will recover in rates their remaining investment in SONGS 2&3 (about $2.7 billion for Edison and about $761 million for SDG&E) over an 8-year period and will earn a reduced rate of return based on the utilities' embedded cost of debt. Edison would earn a return of 7.78% and SDG&E would earn a return of 7.52%.[11]

- o Replace existing variable cost payments per kWh prices for SONGS output by the ICIP schedule. Starting February 1, 1996, the ICIP will start at 3.8 cents/kWh and increase thereafter to 4.15 cents/kWh in 2003. Decommissioning, certain other permanent closure-related expenses and fixed administrative and general (A&G) cost allocations are excluded from ICIP.

- o After December 31, 2003, Edison and SDG&E may sell SONGS 2&3 generation to any customer or groups of customers under prices, terms and conditions conforming to then-existing state and federal law and regulatory procedures. After December 31, 2003, Edison's and SDG&E's CPUC jurisdictional customers will have no further obligations regarding the costs of SONGS 2&3 generation, except for decommissioning and certain other permanent closure related costs. The utilities would continue cost of service rate recovery for SONGS 2&3 of all nuclear decommissioning costs except "incremental" decommissioning costs incurred after December 31, 2003. Furthermore, CPUC jurisdictional customers' responsibility for shutdown costs would be reduced from 100% in 2003 to 10% in 2012.

- o After February 1, 1996, Edison and SDG&E are not obligated to produce power from

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[11] In the event of permanent closure, the rate of return of SONGS 2&3 sunk costs would be set at the utility's most recently authorized Embedded Cost of Debt, converted into a rate of return on rate base, which should apply for the remainder of the eight-year period.

either SONGS 2 or 3 under any circumstances. That means that Edison and SDG&E can shut SONGS 2&3 any time after February 1, 1996 without Commission review. The utilities would incur no disallowance or penalties related to plant operation, purchase of reasonably priced replacement power, or fuel costs. The decision to purchase replacement power could not be subject to reasonableness review. The price of replacement power could be subject to reasonableness review in ECAC proceedings.

- o Nothing in the settlement precludes Edison or SDG&E from requesting that it be permitted to recover certain Nuclear Regulatory Commission assessments regarding incidents or exposures at any location commencing prior to January 1, 2004, or relative to SONGS 2&3 decommissioning, or costs or claims by workers or third parties associated with claims including but not limited to exposure to nuclear radiation or electromagnetic fields.

- o Edison would continue cost of service rate recovery of costs related to Edison's share of Palo Verde Nuclear Generating Station (PVNGS) until or unless superceded by alternative ratemaking. Before February 1, 1996, Edison would prepare a cost effectiveness analysis on PVNGS and a description of alternative ratemaking options.

3.2 Parties' Positions

Edison and SDG&E

Edison's and SDG&E's arguments on the SONGS portion of the settlement are similar and are therefore summarized together. However, Edison's overall argument focuses on the reasonableness of the settlement as a whole, while SDG&E, understandably, focuses on the SONGS portion of the settlement, as that is the portion of the settlement applicable to SDG&E.

Edison believes that the settlement must be evaluated as an integral whole, and not as separate agreements on discrete issues or phases of this general rate case. Edison believes that the entire settlement agreement is reasonable in light of the record, consistent with the law, and in the public interest.

For example, Edison states that the Phase 1 portion of the settlement resulting in a $67 million reduction of the ALBRR results in substantial compromise on the part of itself and DRA, since (by the time reply briefs were filed after the Phase 1 hearings), Edison was seeking a $63 million increase and DRA was recommending a $160 million decrease, a $223 million difference. Edison also states the settlement level will result in an ALBRR below 1992 levels on a constant dollar basis. Edison argues that the Commission should give deference to the agreement reached between itself and DRA on the Phase 1 issues, given DRA's role of representing all of a utility's customers and the fact that DRA reviewed all aspects of Edison's Phase 1 showing. Edison argues that TURN's attempt to selectively update certain accounts to obtain a decrease ignores other areas (such as A&G or postage) in which there was an increase after the close of the Phase 1 evidentiary hearings and for which Edison is not seeking further recovery. Furthermore, Edison believes that the reductions in DSM and RD&D in the settlement are consistent with the law, respond to customer concerns about high rates, positions Edison for greater competition, and are consistent with Edison's resource needs. Edison states that the alternative recommendations from the parties with respect to DSM and RD&D funding are inferior to the balanced approach proposed by the settlement.

With respect to the Phase 3 portion of the settlement, Edison and SDG&E state that the settlement agreement would deliver benefits to Edison's customers including (1) $1 billion, or $235 million net present value (NPV), in reduced customer obligations because Edison and SDG&E have agreed to a reduction of their

respective rates of return on rate base for SONGS 2&3 sunk costs; (2) no increase in customers rates related to nuclear generation above 1994 levels and, in fact, an average annual revenue requirement reduction compared to 1994 levels of $220 million; (3) a shift of SONGS 2&3 operating risk from customers to utility shareholders; and (4) a fixed price schedule for SONGS 2&3 power which means that customers will pay $535 million NPV less for power during the eight-year ICIP period (assuming an 80% capacity factor) than if the plants were shut down.

Edison and SDG&E also state that the settlement is consistent with the Commission's stated desire to prepare utility assets for transition to a more competitive environment. After 2003, SONGS 2&3 power would be sold at competitive market prices or pursuant to whatever alternative regulatory framework may be in place at that time. Edison and SDG&E argue that the settlement creates an incentive for the utilities to ensure optimal performance of their units and eliminates the micromanagement of reasonableness reviews. They state that the settlement does not prevent examination of its terms as part of the electric industry restructure proceeding, and they oppose other parties' objections to or suggested modifications of the settlement.

DRA

DRA supports the Phase 1 portion of the settlement without modification. With respect to the Phase 3 portion, DRA recommends that the settlement ICIP levels be reduced by 0.25 cents/kWh during each year of the ICIP mechanism. This recommendation is based on what DRA describes as new information submitted by Edison in other proceedings after the settlement was negotiated and signed. DRA states this information calls into question the projected ratepayer savings in excess of $1 billion from the continued operation of SONGS 2&3, since this projected savings assumed that the cost of operating SONGS was well below the cost of replacement power. DRA argues that since the settlement

was executed, it has learned from the California Coastal Commission that Edison has proposed to significantly modify the environmental marine mitigation it will perform at SONGS and the expense figures it will incur. Since the ICIP contains over $75 million in costs for marine mitigation work, DRA recommends that any reduction in these costs compared to the $75 million forecast embedded in the ICIP be refunded to ratepayers. Alternatively, DRA recommends removing the marine mitigation expenses embedded in the ICIP and allowing Edison to recover them through traditional ratemaking.

In the event the Commission does not adopt DRA's modifications to the settlement, DRA recommends the Commission reject the nuclear portion of the settlement and proceed with Phase 3 of the general rate case to perform a detailed review of the cost-effectiveness of SONGS 2&3 and PVNGS 1, 2, & 3.

Intervenors-Phase 1[12]

Because of the bifurcated hearing and briefing schedules, the parties addressed the Phase 1 and 3 portions of the settlement

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[12] The following intervenors were active in the Phase 1 portion of the settlement in presenting testimony, cross-examining witnesses, or briefing: CAL-SLA, CEC, DGS, Farm Bureau, NRDC, SoCalGas, and TURN.

Edison filed a motion to strike the DGS' brief on the grounds that DGS did not sponsor testimony opposing the settlement, and that Edison is prejudiced by DGS' decision to file a brief without sponsoring testimony. DGS did not serve testimony, but participated in cross-examination (without objection by Edison) and filed a brief after the Phase 1 portion of the settlement hearings. DGS also actively participated in the Phase 1 evidentiary hearings in 1994 and joined with others in filing an opposition to the Joint Motion of Edison and DRA for a waiver of the settlement rules.

Edison's motion to strike is denied. A December 9, 1995 ALJ ruling waived Rule 51.4's comment requirement on the settlement and instead permitted nonsettling parties to serve testimony. Our Rules of Practice and Procedure do not preclude a party who has not sponsored testimony from otherwise participating in a Commission proceeding (i.e., hearings or briefing) regarding a settlement. Furthermore, Edison has not demonstrated prejudice in that it does not claim that DGS' brief has gone beyond the record. Edison had the opportunity to respond to DGS' arguments in the reply brief.

separately. For ease of summary, we separate these arguments as well, notwithstanding the fact that we review this settlement as an integrated whole.

A number of intervenors urge rejection of the settlement because no group other than the utilities and DRA supports the settlement. Many parties, such as the CBC, NRDC, and DGS, state that the major reductions in the settlement to DSM and RD&D violate state law and policy and Commission decisions. These parties recommend that the Commission adopt a higher level of DSM and RD&D than that proposed in the settlement. Several parties, including DSG, argue against Edison increasing the operation and maintenance (O&M) budget by about $14 million for programs which apparently have DSM objectives but which would not be subject to DSM reporting and criteria, or to one-way balancing account treatment.

TURN argues that the DSM and RD&D portions of the settlement violate law and policy. TURN also states that the fact that the revenue reductions in Phase 1 are achieved almost exclusively from utility programs covered by one-way balancing accounts minimizes the ratepayer benefits from such reductions, since revenue collected for these balancing account activities but not spent would be returned to ratepayers. This is in contrast to revenue collected for other activities included in base rates which, if not spent, goes to the benefit of the utility and its shareholders. TURN argues that with respect to the nonbalancing account activities, of the $124 million which DRA proposed for reduction, the proposed settlement only adopts $12.5 million. TURN points out that with respect to the Phase 1 issues contested between Edison and an intervenor (but not DRA), DRA conceded every one of those issues to Edison. TURN also argues that aspects of the Phase 1 settlement other than DSM and RD&D are contrary to the law. For example, allowing Edison to recover its costs from the California-Oregon Transmission project (COT project) is inconsistent with Commission decisions regarding abandoned

plants. Finally, TURN proposes an alternative means for achieving a reduced revenue requirement to that proposed by the settling parties.

The Farm Bureau, although supporting a reduction in rates and the revenue requirement, does not believe the settlement is in the public interest and urges the Commission to reject the settlement. The Farm Bureau states that the settlement does not go far enough in achieving rate reduction and chooses the wrong elements to obtain the reduction. CAL-SLA opposes the settlement because it incorporates Edison's proposed streetlight acquisition program which CAL-SLA opposed in the Phase 1 evidentiary hearings.

SoCalGas does not oppose the settlement. However, SoCalGas recognizes that pursuant to the settlement, Edison transferred $14 million for fuel substitution, load retention, load management and other marketing activities from DSM programs to non-DSM customer service and information activities as part of O&M expense. As SoCalGas explains, "While Edison intends to pursue fuel substitution, load retention and other activities traditionally regarded as DSM and traditionally subject to the Commission's DSM Rules (see D.94-10-059, Attachment 6), Edison proposes that the $14 million to be transferred to O&M not be subject to the Commission's DSM Rules." (May 2, 1995 Brief of SoCalGas at pp. 1-2.) SoCalGas requests that if the settlement is approved, that the Commission's DSM rules should be lifted for SoCalGas and other utilities as well.

Intervenors-Phase 3[13]

All intervenors who participated in the Phase 3 settlement review urge the Commission to reject the settlement on a number of grounds, including:

- The settlement process excluded interested parties.
- Given DRA's modification, no settlement actually exists.
- All parties to the proceeding (other than the utilities and DRA) oppose the settlement.
- The settlement prejudges the electric industry restructuring proceeding. For example, IBP stated that these issues relate to (a) Edison's competitive position in electric generation, (b) performance-based ratemaking, and (c) treatment of stranded costs. CBERT moved to consolidate this case with the electric industry restructuring proceeding. Many other parties agreed that the appropriate forum to consider the nuclear portion of the settlement is in the restructuring proceeding.
- The settlement violates Public Utilities (PU) Code § 455.5(c) which requires the Commission to open an investigation to determine whether to reduce rates associated with the electric generating facility taken out of service.
- The settlement violates Commission rules (Rule 51.1) by resolving issues which the Commission is addressing in its electric industry restructuring proceeding. Also,

13 The following intervenors were active in the Phase 3 portion of the settlement in presenting testimony, cross-examining witnesses or filing briefs: CCC; IU; CMA; CBERT; CLECA; IBP; TURN; and the Intervenor Unions.

by providing for accelerated recovery without creating incentives for efficient operation, and by failing to minimize market distortions, the settlement violates Commission principles regarding accelerating nuclear depreciation set forth in D.94-05-068.

- The settlement would allow Edison and SDG&E to shut SONGS without Commission review and to recover sunk costs and a return on investment without Commission determination of whether continued operation of SONGS 2&3 is cost-effective.

- The settlement has anticompetitive impacts.

- The settlement will raise rates in the short term. Intervenor Unions and IU point out that the increase in rates due to accelerating nuclear depreciation is not fully offset by the rate reduction caused by lowering shareholder rate of return on sunk costs. This will result in a net rate increase over the period 1996 through 2003. IU points out that actual ratepayer benefits, if they materialize, are deferred until 2003.

- Unlike other generation facilities which become fully depreciated but which have continuing useful life, if after having been fully paid for by ratepayers in eight years of accelerated depreciation SONGS were to remain economically viable, the benefits would accrue entirely to the utilities' shareholders and ratepayers would have no right to power produced at SONGS.

- The ratepayers face significant risk under the settlement which is not balanced by the benefits.

Additionally, Intervenor Unions propose that the Commission make all SONGS-related revenues performance based. The CCC, although urging rejection of the settlement as its primary position, also requests that if the Commission approves the

settlement, all generators have the opportunity to obtain treatment similar to SONGS, with the details to be worked out in the electric industry restructure proceeding. IEP equates SONGS operation in the settlement agreement with an "as-available" resource for which the Commission-adopted valuation is Short-Run Avoided Cost (SRAC). IEP argues that if the Commission concludes the settlement's fixed payment stream is reasonable, it should adopt that payment option for qualifying facilities (QFs) who receive payments based on SRAC.

3.3 Standards of Review

3.3.1 Commission Policy Regarding Review of Settlements

Rule 51.1(e) provides that the Commission must find a settlement "reasonable in light of the whole record, consistent with the law, and in the public interest" in order to approve the settlement. These are the criteria we apply to the settlement before us.

In D.92-12-019, we refined our policy toward settlements by setting forth criteria which would characterize an all-party settlement. The first criterion is that the settlement must enjoy "the unanimous sponsorship of all active parties to the instant proceeding." All active parties in this proceeding do not support the settlement. Because the settlement does not meet the first criterion of an all-party settlement, it is not necessary for us to address the remaining criteria. We will consider the settlement under the three criteria set forth in Rule 51.1(e).

> "However, the standard of review here is somewhat more stringent. Here, we consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law."
> (D.94-04-088, slip op. at p. 8.)

3.3.2 Participation of All Parties in the Settlement Negotiations

Several parties commented about the process used to arrive at this settlement. They oppose a settlement which would resolve far-reaching regulatory and ratemaking issues absent a process which would promote participation by all interested parties. For instance, CLECA complains that it was not afforded a meaningful opportunity to participate in the settlement process but was merely presented with a take-it-or-leave-it option.

Our settlement rules do not require that all interested parties participate in the preliminary discussions leading to the settlement. Indeed, if that were the case, parties might find it difficult to reach settlements as it is often easier to reach consensus with a few parties first, and then attempt to get consensus from a broader array of parties. What Rule 51.1 does require is for the settling parties to hold a settlement conference with notice and opportunity to participate provided to all parties for the purpose of discussing the settlement. The settling parties met Rule 51.1's requirements by holding a properly noticed settlement conference on September 20, 1994.

While the settling parties have met the strict letter of the settlement rules, they did not "bring to the table" those who are in a position to represent all affected groups. If the settling parties choose not to accommodate all affected interest groups, they run the risk of not achieving an all-party settlement, and thus heightening the Commission's standard of review as they have done in this case.

3.3.3 Additional Evidence Regarding Proposed Rate Reductions

In hearings on the settlement, other parties such as TURN presented testimony recommending an alternative means to achieve a rate reduction. (The CBC and NRDC also presented alternative DSM and RD&D recommendations, but seek increases, not further

reductions, of these accounts. The parties did not present some of this testimony in the 1994 evidentiary hearings. Edison objected to TURN selectively updating certain accounts to support a reduction, while ignoring further inquiry into accounts where the costs may have risen since the 1994 hearings.

It is useful to describe the unique posture of this settlement before addressing this issue further. In the usual general rate case, there are specific criteria and a definite time schedule with which a party must conform in order to update testimony. In this case, the settling parties had to obtain a waiver of Rule 51.2 in order to file this settlement with the Commission.[14] The Assigned Commissioner, President Fessler, granted this waiver by ruling which was affirmed by the Commission in the Interim Decision. The ruling also stated:

> "As indicated by the memorandum of understanding, the settling parties are proposing an alternative means of achieving a rate reduction which is not recommended by Edison's or DRA's witnesses or their briefs. Therefore, in fairness, other parties who may oppose the settlement should be permitted to present an alternative means to achieve a rate reduction, even if the alternative means was not in their previous testimony." (Assigned Commissioner's October 5, 1994 Ruling at p. 3.)

The settling parties sponsored supplemental testimony in support of the settlement which recommended reductions, particularly in the DSM and RD&D accounts, which were far below the level previously recommended by the settling parties. (In fact, in some instances, such as RD&D O&M discussed in Section 15.5 below, the settling parties requested more funds for certain sub-accounts

14 Rule 51.2 provides that parties may propose a settlement for adoption by the Commission within 30 days after the last day of hearing. The last day of hearing in Phase 1 was July 11, 1994 and the settlement was filed on November 16.

than Edison requested at the Phase 1 evidentiary hearings. At the invitation of the Assigned Commissioner, other parties submitted supplemental testimony supporting further rate reductions. In rebuttal to this testimony, Edison could have presented specific evidence which demonstrated an offsetting increase in other accounts, but generally chose not to.[15]

Since we have delayed the resolution of this proceeding in order to consider the settlement, fairness and our obligation to the public interest requires that we consider the most recent evidence available at the settlement hearings. We do so in this decision.

3.4 Discussion

We do not believe that the settlement before us is reasonable in light of the whole record, consistent with the law and in the public interest. We therefore reject the settlement based on the following discussion.

What are the affected interests' public reactions to the settlement?

One of the factors in measuring public interest is how the range of affected interests in the proceeding react to the settlement -- i.e., whether they support or oppose the settlement, and whether their support or opposition is mild or strong. The

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15 Edison presented general statements that its property insurance premiums increased "tremendously" after the Northridge earthquake but did not quantify this increase. (See Reporter's Transcript (R.T.) Vol. 58, p. 6641, line 16.) Edison also stated that it suffered losses as a result of the Commission not authorizing it to collect customer service charges in the Interim Decision. Finally, Edison stated its costs increased as a result of the increased postage expenses. (Evidence of increased postage expenses was stricken in the September 1994 update hearings as it was premature.) Other than the increased postage expenses, which evidence Edison chose not to reintroduce, these particular examples raised by Edison are also considered in this decision.

theory is that the parties' self-interest will motivate them to scrutinize and react to the settlement.

Edison and SDG&E represent the affected utility interests. DRA's role is to represent utility customers. Yet DRA does not unconditionally support the settlement as a whole, and Edison and SDG&E oppose the modifications to a key piece of the settlement (the ICIP price stream) which DRA proposes. Thus, on key elements of the settlement, the only parties in support are Edison and SDG&E, who have a common interest in the ownership of SONGS 2&3.

Other than the settling parties, SoCalGas was the only party active in either the evidentiary hearings or the settlement hearings which stated its support for the settlement.[16] Approximately 13 parties oppose the settlement and most oppose it strongly. (See Section 3.2 above.) These parties represent a diverse range of interest groups from residential customers (TURN) to large industrial customers (CLECA and CMA) to public agency customers (DGS) to competitors (CCC, IEP). Therefore, the claims by the settling parties that the settlement is in the best interest of customers and will increase competition are undercut by the settlement's lack of support.

Our discussion continues with a more detailed review of the settlement, first focusing on the Phase 1 portion. This more detailed review and heightened scrutiny is especially appropriate when the settlement is not all-party, and also because we have a complete evidentiary record in Phase 1 and all the issues have been fully briefed. A more detailed review is also necessary as this may be the last general rate case for Edison and some, if not all,

16 SoCalGas primarily offered testimony in the Phase 1 portion of our settlement review which recommended that it receive the same treatment as Edison with respect to non-DSM O&M if in fact the Commission approves the settlement.

of the revenue requirement established here could serve as a baseline for Edison's performance-based ratemaking (PBR) proposal.[17] Based on this review, we also find the following shortcomings.

Phase 1

Q. <u>Does the Phase 1 portion of the settlement provide for a revenue requirement increase or decrease?</u>

The settling parties believe that the Phase 1 portion of the settlement provides for a short-term rate reduction and increases Edison's competitiveness on the eve of competition. They focus on the settlement's $67 million rate reduction from Edison's December 31, 1994 ALBRR as a major ratepayer benefit of the settlement.

We are interested in exploring every available approach to reducing rates and believe that the goals of the settling parties set forth above are laudable. In fact, that is one of the reasons that we took the exceptional step and agreed to waive our settlement rules to review this settlement. However, a close examination of the Phase 1 portion of the settlement demonstrates that it does not provide as substantial a rate reduction as the proponents state.

The DSM and RD&D portions of Edison's revenue requirement are subject to one-way balancing accounts; that is, if Edison does not spend these funds they are refunded to ratepayers. The settlement proponents suggest that even if the Commission were to approve a higher level of DSM and RD&D, that Edison would not spend more than the settling parties request for these accounts.

17 We note that some parties oppose the idea that the revenue requirement established by this case should serve as the starting point for Edison's PBR proposal. (See August 14, 1994 Opening Brief by CLECA at p. 3.) This issue is appropriate to raise in Edison's PBR application, and we do not decide it here.

Therefore, a revenue requirement reduction in these two accounts does not provide for a meaningful ratepayer benefit if the reduction could have been achieved in any event through refunds of the balancing accounts.

The settling parties have proposed major cuts to Edison's DSM and RD&P accounts, yet propose an overall increase in other accounts. When the DSM and RD&D accounts are deducted from both the December 31, 1994 ALBRR and the settlement ALBRR, the settlement actually proposes for the remaining accounts a $58.413 million increase from Edison's December 31, 1994 ALBRR.[18] The settlement also yields to Edison about $20 million from increasing certain customer service charges, such as the service establishment charge.

We do not believe, given the existing complete evidentiary record, it is in the public interest to focus cost-cutting efforts primarily on two balancing accounts while increasing customer service charges (which the record demonstrates disproportionately impact low-income customers). (See Section 10.2 below.) Rather, we believe that the settling parties should have

18 Edison's December 31, 1994 ALBRR was $3,915.543 million. When the DSM and RD&D accounts ($149.232 million and $55.108 million respectively) are deducted, the 1994 ALBRR is $3,711.203 million. The settlement ALBRR is $3,848.238 million. When the DSM and RD&D accounts ($51.000 million and $27.622 million, respectively) are deducted, the settlement ALBRR is $3,769.616 million. Thus, the settlement ALBRR is $58.413 million greater than the December 31, 1994 ALBRR, excluding the DSM and RD&D balancing accounts. (See Exhibit 217 at p. 3, lines 1, 13, and 15.)

given all of Edison's operating expenses the same scrutiny they did the DSM and RD&D accounts.[19]

Burden of proof

In the Phase 1 evidentiary record, Edison failed to meet its burden of proof in its funding request for, inter alia, its costs of the COT project (Section 8.3), portions of its economic development program (Section 12), and certain non-DSM O&M (Section 11). The settling parties' testimony did not remedy this situation. For example, we do not exempt the settling parties' requested ratepayer funding of activities that cause DSM impacts from scrutiny under our DSM rules simply because they have changed the name or accounting treatment of certain activities. The settling parties have failed to demonstrate how the requested shift of DSM funds to non-DSM O&M complies with our past DSM decisions. Edison did not meet its burden of proof in other areas as well, such as total compensation (Section 19) and health care costs (Section 14).

Phase 3

On key elements of the Phase 3 portion of the settlement, the only parties in support are Edison and SDG&E. This indicates that the settlement seems to lack the broad and continuing support which we would prefer in settlements that we adopt. In developing

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19 Edison suggests that its cost-containment measures implemented for the balance of its O&M accounts make any further cost cutting unnecessary. In the evidentiary hearings, there was little, if any, difference between the parties with respect to certain O&M categories, such as Hydraulic and Steam and Other Power Production. We applaud Edison's cost-containment program to the extent it reduced costs in these areas. However, in the 1994 evidentiary hearings, DRA, as well as other parties such as TURN and FEA, proposed reductions to other Edison accounts. Many of these proposals are well substantiated. (See our account by account discussion from Section 4 et seq. below.) Yet few of DRA's recommendations other than those concerning DSM and RD&D and none proposed by the other parties were incorporated in the settlement.

our guidelines for SONGS 2&3, we carefully review the Phase 3 testimony offered by Edison and SDG&E.

We find merit with Edison's and SDG&E's conceptual framework with regard to Phase 3 issues although we have concerns with particular aspects that we believe are inconsistent with the law and not in the public interest. We also note that portions are inconsistent with the general principles regarding stranded cost recovery that we recently have adopted in our restructuring proceeding (D.95-12-063). As Edison itself noted, the proposed settlement was not meant to prejudge or predetermine the CTC issues related to restructuring. (See Exhibit 236).

In this decision we adopt guidelines which change the Edison and SDG&E proposal. We will allow Edison and SDG&E 25 days from the effective date of this decision to respond to the policy which we propose for SONGS. If they accept, the utilities should submit a detailed proposal consistent with the policy which we adopt here. Other parties may comment on the utilities' filing no later than February 20, 1996. If the utilities do not accept our SONGS policy, then we will resolve this issue either in a separate opinion in this rate case or as part of another appropriate proceeding.

We are concerned with the Phase 3 issues which address the risk/benefit trade-off for ratepayers. We briefly review our concerns with the Phase 3 based on the record before us. This discussion is not precedential to a review of this matter in a different context.[20]

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20 Much of the following discussion is focused on Edison since this proceeding is Edison's general rate case and Edison owns the largest share of SONGS 2&3. SDG&E is a party to the settlement and is also 20% owner of SONGS 2&3. SDG&E joined in this settlement in Edison's rate case in order to ensure consistency of

(Footnote continues on next page)

Short-term benefits and risks

The key element in the SONGS proposal is the accelerated depreciation schedule, which by its nature requires ratepayers to bear more costs sooner than would have occurred under existing ratemaking treatment. Until 2003, the revenue requirement under the proposal will exceed the requirement under existing ratemaking due to accelerated depreciation of the plant.[21] Edison and SDG&E argue that ratepayers will receive approximately $235 million NPV (net present value) as a result of their proposed use of the embedded cost of debt for the rate of return. However, the horizon for this net present value calculation extends well beyond 2003 which implies that the net benefits for the ratepayers are relatively remote.

For example, the costs of the SONGS 1 and the Palo Verde Phase-In ratemaking procedures are scheduled to be phased out of the revenue requirement beginning in 1996. Yet Edison's customers

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treatment of SONGS 2&3 O&M costs and capital expenditures and to avoid litigating SONGS 2&3 costs and expenditures in more than one proceeding. SDG&E pointed out that the Commission traditionally has considered the SONGS 2&3 related costs that Edison bills to SDG&E in Edison's general rate case. Thus, our resolution today applies to SDG&E as well as Edison.

21 Taken in isolation, the average effect on Edison's revenue requirement of the Phase 3 portion of the settlement is a $72 million increase each year over the 8-year period due to the accelerated recovery of sunk costs and the ICIP for SONGS 2&3

will not realize the full benefit of this rate decrease because of offsetting increases which occur in the Edison-SDG&E proposal.[22]

Edison's and SDG&E's ability to shut SONGS 2&3

Edison and SDG&E state that another benefit to ratepayers is the fixed ICIP price for future SONGS 2&3 output. This fixed ICIP price gives ratepayers price certainty for future SONGS 2&3 incremental costs. They state that the ICIP will provide price certainty for ratepayers against future capital overruns, and that the ICIP will shift the risk of plant performance from the customer to the shareholder because incremental capital costs are part of the ICIP, which ratepayers pay only if SONGS 2&3 operates. In return, the shareholders are guaranteed price certainty for all SONGS 2&3 output through 2003. Some uncertainty arises in the ability of Edison and SDG&E to shut down SONGS 2&3 without Commission approval.

The ICIP benefit declines if the ICIP price exceeds the cost to operate SONGS 2&3, or if the actual capacity factor of SONGS 2&3 exceeds that assumed in the ICIP. Conversely, if the cost of operating SONGS 2&3 exceeds the ICIP price stream, the ratepayers will benefit by the smaller ICIP. However, ratepayers will not necessarily benefit by receiving price certainty, since under their proposal, Edison and SDG&E[23] could shut the plant down and still receive their sunk costs. Moreover, if operation of SONGS 2&3 were cost-effective but operating costs exceed the ICIP

22 In fact, in order to avoid a net rate increase in 1996, because the full impact of the revenue decrease due to SONGS 1 and Palo Verde does not take place for all of 1996, Edison proposes to defer recovery of about $120 million from 1996 to 1997 with interest.

23 There is some controversy on record whether Edison would need SDG&E's concurrence to effectuate a plant closure, but we need not address that issue here.

price stream, Edison might ask the Commission to modify the settlement agreement to increase the ICIP in lieu of a plant closure. (See R.T. Vol. 63, p. 7323.)

The utilities state that their proposal does not provide incentives for them to shut the plant, that they would weigh a multitude of factors in making the decision, and that ideally, it would take about seven years lead time to shut the plant. The utilities would have the ability to shut SONGS 2&3 without Commission review under the Edison-SDG&E proposal. This ability seriously erodes the asserted ratepayer benefits from the ICIP provisions.[24]

Disposition of SONGS 2&3 power after 2003

Under traditional ratemaking after the utility recovers the capital costs of a plant, the ratepayers primarily pay the variable costs associated with continued operation. We have approved the construction of plants (such as nuclear or hydro) with high capital costs but low operating costs, partly in recognition of the benefit of the low costs which can occur after the utility recovers its original plant investment.

Under the Edison-SDG&E proposal, ratepayers will pay for SONGS 2&3 sunk costs. Assuming continued operation of SONGS 2&3, ratepayers benefit from this provision by paying a reduced rate of return. Shareholders benefit by gaining certainty of the recovery of their nuclear investment.

The utilities will not have an obligation to serve ratepayers with SONGS 2&3 generation after 2003. After 2003, the

24 For example, Edison asserts that a fixed price schedule for SONGS 2&3 means that customers will pay $535 million NPV less for power during the eight-year ICIP period (assuming an 80% capacity factor) than if the plants were shut down. Assuming arguendo the existence of this benefit, it is one ratepayers would not realize if Edison and SDG&E shut the plant.

utilities can shut down the plant or sell the energy at market prices to any customer. These market prices could exceed the plant's variable costs which would reduce the ratepayer benefit. Of course, the ratepayers will receive no benefit after 2003 if the plant shuts down. For the utilities to retain all profits after 2003 does not balance risk and reward appropriately.[25]

o. Proposed Modifications

Given the above concerns and with the record in this proceeding, we adopt changes to balance the ratepayer and shareholder interests. As also noted before, the lack of broad and continuing support for the resolution of Phase 3 issues[24] leads us to treat Edison's and SDG&E's cost recovery proposal for SONGS 2&3 as a joint proposal.

In this decision we adopt guidelines which change the Edison and SDG&E proposal. We will allow Edison and SDG&E 25 days from the effective date of this decision to respond to the policy which we propose for SONGS. If they accept, the utilities should submit a detailed proposal consistent with the policy which we adopt here. Other parties may comment on the utilities' filing within 14 days of its service. If the utilities do not accept our SONGS policy, then we will resolve this issue either in a separate opinion in this rate case or as part of another appropriate proceeding.

First, we find the ICIP pricing mechanism reasonable. The 78 percent capacity factor used to calculate the ICIP is only slightly lower than the recent historical value of 79.8 percent for

25 The settlement provides that shareholders will pay for continued operation of SONGS 2&3 and certain decommissioning costs and shutdown costs after 2003. While clearly a benefit to ratepayers and an additional obligation to shareholders, this provision does not appear to offset the major concession ratepayers are making with respect to receiving the continued output of SONGS 2&3 after 2003.

the period of 1988 through 1995 (Calculated based on Exhibits 11, 57, 236, and 237). Setting the ICIP capacity factor slightly lower than this recent historical value gives the utility an incentive to keep the plant operating if the utility believes it can exceed ICIP performance levels.

We are also concerned that the plant operate during hours of peak demand when production from SONGS has the most value. The ICIP formula values SONGS generation at the same price for each hour of the day despite the fact that energy prices vary hourly. The value of SONGS generation to ratepayers is enhanced to the extent that plant is available and generating during hours of peak demand (generally weekdays during Summer months). We agree with TURN's testimony that to strengthen the incentive for reliable summer peak operation. Therefore, we increase both the surcharge and the number of hours in which it is applied. We do not go so far as TURN urges. Based on Edison's comments on the Proposed Alternate Decision of Commissioner Fessler, this change would have only a minor effect on the overall economics of the settlement (See Edison's Comments, p. 8).

We do not propose any modifications to the marine mitigation and monitoring cost embedded within the ICIP.

To summarize the ICIP pricing mechanisms:

- o Set the ICIP based on a 78% capacity factor[26]
- o The ICIP would be multiplied by a factor of 1.2 for the equivalent of the first 800 hours of Full Operation for each unit between 10:00 a.m. and 10:00 p.m. on

26 Under the settlement the ICIP after tax stream incorporating a 78% capacity factor is as follows:

	1996	1997	1998	1999	2000	2001	2002	2003
$/Kwh	0.0380	0.0385	0.0400	0.0400	0.0405	0.0410	0.0415	0.0415

weekdays during each period of June 1 through September 30. The ICIP would be multiplied by a factor of 0.80 for the equivalent of the first 800 hours of Full Operation for each unit for any hours of the year not covered above. The ICIP would be multiplied by a factor of 1.00 for output for the remaining hours of operation during a year.

o Continue to include the marine mitigation and monitoring costs within the ICIP.

In D.95-12-063, we propose a general policy for stranded cost recovery. There we decided that while use of a debt-return is appropriate for the debt component of a stranded investment, a rate of return of 90% of the debt-return is appropriate for the non-debt (i.e. equity) share of the stranded investment. Similar treatment will apply for setting the appropriate rate of return for SONGS 2 & 3 recovery. Therefore, Edison should earn a rate of return of its embedded cost-of-debt on the debt share of SONGS undepreciated book value, and a return on its non-debt (i.e. equity) share of 90% of the embedded cost of debt. SDG&E's share of SONGS will receive similar treatment based on its embedded debt costs.

Finally, we are concerned with the utilities' unilateral ability to shut down either SONGS 2 or 3 and still receive their sunk costs at a reduced rate of return. This discretion is not consistent with PU Code Section 455.5. To address this issue, we adopt the following policy:

o If the SONGS 2&3 units, or any one of the units, discontinue operations either permanently or for a period of nine or more consecutive months, the utility shall immediately notify the Commission as set forth in PU Code § 455.5(b). The reasonableness of any expenses related to these units will be reviewed by the Commission under, inter alia, PU Code § 455.5 in whichever of the two following events occurs earliest: (a) a proceeding to be initiated by Edison within 45 days of a permanent shutdown decision or (b) in an

> investigation initiated by the Commission within 45 days of receiving the notification specified in PU Code § 455.5 (b). Review of the reasonableness of any costs will be applied retroactively to the date of the shutdown.

The above modification helps to ensure that Edison has a strong incentive to continue operating the plant throughout the 2003 period.

Finally, we adopt the following policy to address the sharing of profits between ratepayers and shareholders in a post-2003 market:

- o Beginning January 1, 2004, ratepayers will be entitled to 50% of the benefits associated with the SONGS 2&3 units in a post-2003 electricity market. This benefit can be valued by either (1) the audited profits from continued operations, or (2) a Commission approval of a gain-on-sale of the plant, or (3) a third-party appraisal of the value of the plant if it remains with Edison and SDG&E. Other approaches to valuation may also be considered. The utilities will notify the Commission by application, filed no later than July 1, 2002, as to their preferred approach to the valuation of the plant for the period beginning January 1, 2004.

In this decision we adopt guidelines which change the Edison and SDG&E proposal. We will allow Edison and SDG&E 25 days from the effective date of this decision to respond to the policy which we propose for SONGS. If they accept, the utilities should submit a detailed proposal consistent with the policy which we adopt here. Other parties may comment on the utilities' filing no later than February 20, 1996. If the utilities do not accept our SONGS policy, then we will resolve this issue either in a separate opinion in this rate case or as part of another appropriate proceeding.

We do not expect any new proposals to be part of the utilities' filing. The utilities' proposal should specify a start-up date of May 1, 1996.

3.5 Burden of Proof in Absence of Settlement

If the Commission were to decide the Phase 1 issues in absence of a settlement and on the existing record, Edison recognizes that, as applicant, it has the burden of proof. (Edison's Opening Brief at pp. 19-22; see also, our discussion in SoCalGas' general rate case for test year 1994, D.93-12-043, slip op. at pp. 7-9.)

Edison states that its voluminous Phase 1 showing is the result of its attempt to present, by officers and employees in each area of the company, a thorough initial showing which is also "userfriendly," i.e., with executive summaries, road maps, etc. Edison recognizes that quality and quantity are not necessarily synonymous, but states that the relatively few deficiencies DRA found in its Notice of Intent (NOI), a preliminary filing, are "indicative of Edison's success in satisfying the Commission's requirements for a prima facie showing." (Edison's Opening Brief at p. 22.)

We leave the issue of whether or not Edison has met its burden of proof to be discussed, as appropriate, in the following sections which address specific areas of controversy. However, it is important to note that DRA has a compliance and not an advocacy role at the NOI stage of a general rate case. That is, DRA is to determine whether a utility's application complies with the rate case plan's "Standard Requirement List of Documentation Supporting an NOI." (See D.89-01-040, 30 CPUC2d 576, 582, Appendix B.) The

fact that DRA found relatively few deficiencies at the NOI stage does not establish that Edison has met its burden of proof.[27]

The following sections review Edison's Phase 1 request, largely on an account-by-account basis.[28] The dollar expenses are stated in 1992 dollars unless otherwise indicated, and are appropriately escalated in the tables attached to the decision. In the following sections, we summarize the parties' positions and discuss the reasoning behind our conclusions. As usual in such proceedings, the record is voluminous. We concentrate on the chief points of contention and do not try to summarize every nuance in individual positions.

27 Although the utility has the burden of proof on all issues, we have indicated in a prior proceeding that this burden is not in all areas so burdensome as one might assume. (See D.93-12-043 at p. 9.)

> "We generally rely on intervening parties to identify proposals or funding requests which should be subject to scrutiny by the Commission. Our reliance on other parties to set a framework for litigation in a general rate case derives from the fact that a single ALJ cannot review an entire rate case showing without an extraordinary expenditure of time and effort. Because intervenor resources are limited and their priorities may differ from ours, the parties may overlook proposals that the Commission might otherwise consider questionable. Nonetheless, where a proposal or funding request has not been challenged by an intervenor, we generally adopt the utility's request as a practical reality of the decision-making process. In those cases, the utility's burden of proof is indeed light."

28 The Federal Energy Regulatory Commission (FERC) has established a uniform system of accounts for electric public utilities. (See 18 C.F.R. Part 101 et seq.)

4. Sales and Customer Forecasts

4.1 Positions of Parties

Prior to the Settlement

Edison and DRA agreed to a sales forecast of 72,070 gigawatt-hours (gWh), but disagreed on the customer forecast.

Edison's econometric customer model is driven primarily by forecasted changes in building permits, and is keyed to the UCLA Economic Forecast for California. DRA adjusted Edison's original econometric forecast of 4,204,326 customers downward to 4,176,526, a decrease of 27,800. DRA observed that recorded new customer additions for 1993 were considerably lower than Edison's forecast (18,600 vs. 30,000), and that the continuing Southern California recession likely would similarly depress customer growth in the test year. According to DRA, the recession "is not following the usual pattern of most recessions since 1945 in that housing is continuing to stagnate rather than to lead the rest of the economy into a recovery." (Exhibit 402 at p. 3-6.) DRA further stated that Edison's "idle meter" count -- an indicator of housing market conditions -- substantially increased from 1991 to 1993. DRA therefore revised downward Edison's forecasted 1994 customer growth from 40,000 to 30,000, and 1995 growth from 60,000 to 45,000. Upon converting forecasted customer additions from a year-end to an "average customer" basis, DRA arrived at its forecast of 27,800 fewer customers for test year 1995.

After DRA filed its testimony, Edison submitted Exhibit 64 which, based on an updated forecast submitted in its ECAC filing (A.94-05-044), estimated 35,200 new customers in 1994, and 49,900 in 1995. These revisions produced an average customer total of 4,184,154 for test year 1995, just 7,628 higher than DRA's figure.

Edison's ECAC customer forecast was made shortly before the Northridge earthquake of January 1994. Edison, however, stood by its pre-quake numbers. Edison explained that the UCLA Economic

Forecast's prediction of a spurt of post-quake economic activity suggested that its numbers should, if anything, be adjusted upward rather than downward. Edison noted that the latest UCLA forecast (March 1994) predicted that California would actually begin recovering from the recession in the second quarter of 1994, one quarter earlier than its prior (December 1993) forecast indicated. UCLA's March 1994 forecast also predicted a sharp increase in residential building permits, considerably higher than the September 1993 forecast. Edison also anticipated the return to active customer status of thousands of idle meters. Edison thus believed any further downward adjustment to the customer forecast would be unwarranted.

DRA maintained that Edison's model has historically overestimated customer additions, and that its professional judgment was superior even to Edison's updated model. TURN supported DRA, commenting that Edison's updated forecast was closer to DRA's recommendation than to Edison's original forecast. Edison responded that its model yields sufficiently accurate results when properly interpreted, and that DRA's forecast lacks a rigorous quantitative foundation.

Settlement

Noting that neither DRA nor Edison "could demonstrate the superiority of its forecast," the Settlement Agreement split the difference between them, resulting in a forecast of 4,180,340 customers. (Settlement Joint Comparison Exhibit at p. 10.)

4.2 Discussion

The heat content of this dispute was excessive, given that Edison's revised customer forecast exceeds DRA's by less than two-tenths of 1%. Since the record provides no solid basis for choosing between the parties' close forecasts, we adopt the average result of 4,180,340 customers, in addition to the undisputed sales forecast of 72,070 gWh.

5. Steam and Other Power Production

5.1 O&M Expenses

In its initial application Edison requested $198.470 million for labor and nonlabor steam power production expenses. At the beginning of evidentiary hearings, Edison modified its initial request to that of DRA's expense recommendation of $198.368 million. Similarly, Edison initially recommended the Commission approve $19.071 million for other power production expenses, but modified its request to that of DRA's recommended $17.124 million. The settling parties concur with DRA's recommendations. We adopt DRA's recommendations for these FERC accounts.

5.2 Capital Expenses

Although Edison and DRA differed in their recommendations in this category at the commencement of evidentiary hearings, at the conclusion of the hearings Edison and DRA concurred on these expenses, thus not raising issues for us to resolve.[29]

DRA withdrew its recommended reduction of Edison's 1993 beginning-of-year plant balance by $7.8 million to reflect DRA's auditor's adjustment for asbestos removal costs because of a FERC ruling which moots this recommendation.

DRA also recommended that estimated, rather than recorded, heat rates be incorporated into the production cost models used in Edison's ECAC proceedings. The parties agree to defer consideration of this issue until Edison's next ECAC proceeding, since Edison pointed out that the energy review and production cost model referred to in DRA's recommendation are typically considered in the ECAC proceeding. We agree that the parties may raise this issue in Edison's next ECAC proceeding.

29 The parties also raise two other separate issues (one flowing from the differences in overhead expenses and one which arose after the close of hearings) which we address in Section 17.

6. Nuclear Power Production

At the close of the 1994 hearings, the parties were in agreement regarding Edison's forecast of O&M and capital nuclear power production expenses except for the issues set forth below and discussed in Section 17. However, the nuclear expenses we authorize today may be adjusted prospectively once the SONGS issues addressed in Section 3 are resolved.

6.1 O&M Expenses

6.1.1 SONGS 2&3 O&M Savings

DRA proposed that the Commission amortize the O&M savings realized in the attrition years over the rate case cycle, for a reduction in Edison's request of $1.968 million. Edison opposed this request, stating that normalizing the benefits of capital additions that are estimated for future years removes the effect of productivity benefits that the Commission expects utilities to use to offset cost increases not yet authorized in rates that will be incurred between rate cases.

In the settlement, DRA agreed with Edison in order to obtain the overall ratepayer benefits. We agree with Edison and deny DRA's requested reduction.

6.1.2 Expenses to Increase SONGS 2&3 Capacity Factor

Edison requested $3.932 million to maintain three performance improvement initiatives for SONGS 2&3 begun in the late 1980's. DRA recommended that the O&M expenses estimated to increase total capacity factor be shared 50/50 between shareholders and ratepayers, for a reduction in Edison's request of $1.475 million. DRA did not oppose the expenditures nor the derivation of the costs, but stated that it would not be equitable for ratepayers to pay for all costs of the program and to share in only half of the benefits.

The settling parties agreed that the funds forecast for the continuation of these three performance improvement programs should be included in rates. The settling parties stated that

because the expenditures are necessary to maintain ongoing programs implemented during periods of improving plant performances, the parties agreed not to disallow the requested O&M expenditures. We deny DRA's requested reduction.

6.1.3 Palo Verde Nuclear Generating Station (PVNGS) Oversight Expenses

DRA recommended that the Commission remove the Palo Verde investigation (I.89-12-025) associated expenses from Edison's forecast of PVNGS oversight expenses. This recommendation results in a $232,000 reduction. The settling parties agreed with DRA because the forecast should not include the unusual expenses related to the Palo Verde investigation. We adopt DRA's recommendation.

6.1.4 Other Nuclear Proposals

Several parties suggest modification to our Nuclear Unit Incentive Procedure (NUIP). The NUIP establishes what is commonly referred to as the target capacity factor for Edison's nuclear power plants. Edison recommended that the current target capacity range be modified from the existing 55-80% to 65-78%. All parties agree on increasing the level of the floor to 65% consistent with the trend of nuclear industry plant performance and target capacity factor improvements over the last decade. However, DRA and CLECA recommended increasing the ceiling to 83.5%.

The target capacity factor issue may overlap with our resolution of SONGS 2&3 issues as set forth in Section 3. Therefore, we do not resolve this issue here. Based on similar rationale, we do not address a DRA proposal to establish a 65-day standard for forecasting future nuclear refueling outages, or CLECA's cost effectiveness issues. Nor do we address Edison's proposal to eliminate reasonableness reviews when Edison's nuclear capacity factor exceeds the floor of the target capacity factor, or to change the burden of proof for the party alleging

unreasonableness when the target capacity factor is less than the floor.

6.2 Capital Expenses

6.2.1 SONGS 2&3 Refueling Project Costs

Edison forecasted $22.5 million for each of the SONGS 2&3 Cycle 8 work orders based on historical expenditures and a list of projects planned at the time of the application. Edison also stated that it has properly evaluated, reviewed, and justified each of the projects included in the $22.5 million for each Cycle 8 work order and all currently identified projects for the Cycle 8 refueling outages have been approved by the Plant Modification Review Committee (PMRC).

DRA recommended reducing Edison's forecast by $5.3 million per unit primarily because not all projects had been approved by Edison's PMRC.

In the settlement, DRA agreed to adopt Edison's forecast of nuclear additions and to include the SONGS Cycle 8 plant modifications, the marine education center and miscellaneous projects in the plant-in-service forecast. The Settlement Comparison Exhibit at p. 166 states

> "Edison's forecast of $22.5 million for each of the SONGS 2&3 Cycle 8 plant modification expenditures included in its GRC (general rate case) Application is consistent with historical expenditures and a list of projects known at the time of the Application. The projects have become better defined as the outages drew closer allowing Edison to make changes to the work orders to reflect changing plant operational needs. Edison's estimate for the projects included in the $22.5 million for each Cycle 8 work order and currently identified projects for the Cycle 8 refueling outages have been approved by the PMRC."

We deny DRA's requested disallowance.

6.2.2 Flexible Refueling Outage Schedule Request

Edison requested continuation of the "flexible refueling outage schedule" adopted and affirmed in Edison's last three general rate cases. This permits Edison to estimate attrition year refueling outage expenses in the event the number of outages in the attrition year differs from the number in the test year. Although DRA proposed modifications to Edison's attrition filings, it did not oppose Edison's flexible refueling outage schedule request.

For the past several years, adjustments for varying outage schedules have been effective in estimating attrition year expenses. Notwithstanding the fact that we eliminate advice letter filings seeking attrition year increases (see Section 21 below), Edison should file its flexible refueling outage schedule request as an advice letter in attrition years using test year values of O&M expenses for refueling. Edison should not expand this filing to include other items not previously included in the flexible refueling outage schedule request, such as escalation fees associated with the disposal of low-level nuclear waste.

7. Hydraulic Power Production

7.1 O&M Expenses

Edison originally estimated $24.2 million for its test year 1995 expenses for O&M hydraulic power production expenses, and subsequently revised this amount to $23.9 million. DRA concurred with the revised amount prior to the settlement and the settlement reflects this amount.

TURN recommended several reductions to Edison's request.[30]

30 In its testimony, TURN also recommended that Account 543.100 be reduced by $25,000 on the basis that Edison charged nonutility timberlands management to this account. TURN did not argue this

(Footnote continues on next page)

<u>Account 536.100</u>. TURN proposed reducing Account 536.100 expenses by $190,000 as a result of normalizing Edison's estimated FERC fee payment over six years. Both Edison and TURN agreed that since Edison's rebuttal testimony indicates that Edison received and paid the actual FERC bill and was reducing its estimate for this account by $317,000, the issue raised by TURN is moot.

<u>Account 544.100</u>. TURN recommended capitalizing the wicket gates replacement costs on Edison's Big Creek No. 3 hydroelectric plant, thus removing $649,000 in expenses from this account. TURN contended that the costs of the wicket gates being replaced were originally capitalized, the replacement gates are expected to last for 30 years, and the cost of the gates are of the same magnitude as those of generator rewinds, which Edison treats as a capital investment. TURN also contended that the wicket gates are a major component of Edison's hydroelectric plant, in that they are critical to the successful operating of the plant, their replacement will extend the life of the plant, and failure to replace them will render the generating units inoperable.

Edison responded that replacement of the wicket gates is not a significant, nonrecurring event. Edison explained that although this expense, standing alone, may be considered a significant replacement, the gates are a minor component item of the hydraulic turbine. Edison capitalized the cost of generator rewinds because the cost of rewinding the generator is in essence

(Footnote continued from previous page)
issue on brief, presumably because Edison's rebuttal testimony clarified that this account did not include costs for nonutility activities.

the rebuilding of the entire generator. If it were required to capitalize every component originally capitalized, Edison states it would end up capitalizing all components replaced during maintenance.

We agree with TURN that the costs of the wicket gates should be capitalized. We find that this is a nonrecurring expense related to a specific plant. Edison did not dispute the fact that these gates are expected to last for 30 years. This is different than general replacement costs, for example, for motors, which are expected to be replaced every few years on Edison's system. Edison's workpapers also described the gates as an important component of controlling water through the units. (Exhibit 741, section C at p. 179.) Therefore, expenses in Account 544.100 should be reduced by $649,000, with a corresponding increase in plant in service.

7.2 Capital Expenses

DRA agreed with the reasonableness of Edison's hydro capital estimates. TURN disagreed, recommending that plant be increased for capitalization of the wicket gates. Based on our discussion above, we agree with this recommendation. TURN also recommended the removal of $5,332,000 of existing plant in service under the theory that this amount is being double recovered by Edison. This issue is addressed in Section 17 below. Subject to our discussion in Section 17, we approve Edison's hydro capital estimates, with the adjustment for the wicket gates recommended by TURN.

8. Transmission

8.1 O&M Expenses

Edison requested $73.1 million for its 1995 transmission-related O&M expenses, which represents a 1.49% average annual decrease from 1992 recorded expenses. We commend Edison on achieving these savings, and encourage Edison to continue to

monitor other utilities' practices and procedures in this area to achieve further O&M cost savings.

DRA did not oppose Edison's request at hearings, and the settling parties agreed to Edison's request. TURN opposed Edison's request on several issues which we address below.

8.1.1 Sylmar Converter Station

Edison requested $1.1 million for Account 560.200, primarily for costs associated with the Sylmar Converter Station. Edison and the Los Angeles Department of Water and Power (LADWP) each own 50% of this plant, and share O&M costs by contractual agreement on a 50/50 basis. TURN recommended that the Commission decrease Edison's estimate by $156,000 and base these expenses on Edison's expenses in the last recorded year because Edison has not demonstrated why these costs should increase.

Edison explained that while overall operating expenses at the Sylmar Converter Station declined approximately $1 million from 1989 to 1992, the capacity and technical complexity of the station increased, and this station has a key role in the reliable performance of the Western Systems Coordinating Council. We agree with TURN that Edison's justification is conclusory and adopt TURN's recommendation on this issue.

8.1.2 Training and Safety Meetings

TURN recommended that the Commission reduce Account 566.1 by $250,000 on the grounds that training expenditures for both steam generation and distribution units are not projected to increase during the test year, and training costs are expected to decrease for the hydroelectric unit. TURN recommended using a two-year average of such expenses rather than Edison's seven-year trend. Edison responded that transmission training costs are rising due to automation and cross-crafting, coupled with environmental compliance and new safety rules. Edison also stated that TURN's proposed reduction could seriously affect the safety and reliability of Edison's transmission system. We find Edison's

request reasonable here in light of the record and therefore deny TURN's request.

8.1.3 Structural Maintenance

Edison used a seven-year average to estimate Account 569.100 maintenance expenses. TURN recommended using a five-year average which would result in an $18,000 reduction of labor and a $308,000 reduction of nonlabor expenses. TURN explained that although the activities covered in this account are weather-driven, so too are the activities in Account 571.300 (maintenance of transmission line rights of way) which costs Edison estimated using a five-year average. TURN recommended a consistent methodology be used in evaluating accounts.

Edison explained that a seven-year average is necessary to estimate expenses here which are influenced by weather and thus vary over time. Edison stated that a reduction in its estimate could lead to more costly future repairs because a large number of the maintained structures are older.

Edison should use the same estimating methodology for similar accounts for consistency of evaluation. Therefore, we adopt TURN's recommendation.

8.1.4 Provision for Property Damage

TURN recommended $171,000 reduction from Edison's request in Account 573.1, based on the same rationale as for Account 569.100. For the reasons stated above, we grant TURN's request.

8.2 Capital Costs

No party opposed Edison's estimate of $313.587 million for transmission capital expenses, which we adopt.

DRA recommended a $225,000 refund to ratepayers through the Electric Revenue Adjustment Mechanism (ERAM), effective on January 1, 1995, for Edison's overcollection of mechanically switched capacitor equipment at Table Mountain. Edison did not oppose this recommendation, which we adopt.

In D.92-12-022 from Edison's last general rate case, the Commission ordered Edison to establish a memorandum account effective January 1, 1992 to track the revenue requirement associated with disputed mechanically switched capacitor costs at Table Mountain until the issue could be resolved in this rate case. (D.92-12-044, slip op. p. 13, Ordering Paragraph 7.) In this case, Edison proposes to allocate $544,000 of the mechanically switched capacitor costs to the High Voltage Direct Current Expansion Project and $3,455,000 of the mechanically switched capacitor costs to Pacific Intertie voltage support. DRA agrees that Edison's total cost allocation proposal is reasonable and that the mechanically switched capacitor was needed to prevent low voltage conditions during certain disturbances. However, DRA found that the $225,000 refund to ratepayers which we discuss above is necessary because Edison overcollected about 5.5 months of revenue in 1992 on the mechanically switched capacitor. Since there is no dispute regarding Edison's proposed cost allocation of mechanically switched capacitor costs, there is no further need for the memorandum account which was used to track these costs.

In its original testimony, DRA made several noncost-related recommendations in this area, which Edison did not oppose. The settling parties did not address the first three recommendations in the settlement and agree on the fourth recommendation. First, DRA recommended that Edison not be allowed to claim any O&M expenses for the mechanically switched capacitor equipment until after July 2013 unless the 23-year agreement between PG&E and LADWP is cancelled or modified. This is so because the inter-utility agreement includes payment by Edison for maintenance, and Edison is capitalizing these payments in this proceeding. We adopt this DRA recommendation.

Second, DRA recommended and we direct Edison to prepare a report on how the upgraded transmission-related equipment, such as circuit breakers, disconnect switches, transformers, etc. related to the 500 kilovolts (kV), 200 kV and other substations, performed during the January 1, 1994 Northridge earthquake, and what changes should be considered with respect to transmission lines and other lower voltage facilities in its Seismic Upgrade Program. Edison

should also include in its report a short discussion of its seismic damage insurance coverage, if any, for these facilities. Edison should file this report no later than March 1, 1996 in this docket, and serve it on the parties to this proceeding and on the Commission's Safety and Enforcement Division.

Third, DRA stated that utilities have used compact transmission line designs to cut land use and associated construction costs. We direct Edison to consider the use of more compact designs for its new substations and lines to the extent these designs are a cost-effective means of reducing land, right-of-way, and equipment costs.

Fourth, DRA recommended that Edison should include certain information with its application for a reinstated or new certificate of public convenience and necessity (CPCN) for the Devers-Palo Verde No. 2 500 kV line. The parties agree to this recommendation in the settlement agreement and we adopt it.

8.3 California-Oregon Transmission Project (COT project)

8.3.1 Positions of Parties

Prior to the Settlement

Edison sought recovery of $8,312,510.38, which represents its share of costs for the COT project which the Transmission Agency of Northern California constructed (amortized over three years). Edison participated in the transmission project together with other public and municipal utilities, including Pacific Gas and Electric Company (PG&E) and SDG&E. In D.91-04-071, the Commission denied Edison, PG&E, and SDG&E a CPCN to participate as owners of the COT project.

Edison requested recovery of the funds it invested in this project. If Edison's request is granted, the funds invested in the abandoned project are amortized and included as an amortization expense in FERC Account 930.2, Miscellaneous General Expenses. Prior to the settlement, DRA and TURN opposed Edison's request because they did not believe Edison had met its burden of proof in demonstrating cost recovery for a plant which is not used and useful.

Settlement

The settling parties agreed that Edison should recover its COT project costs, but gave no rationale other than that presented by Edison in the evidentiary hearings.

8.3.2 Discussion

The Commission has a long-standing rule that a utility should not recover the costs of plant not used or useful, unless the utility can show:

> "(1) that the project ran its course during a period of unusual and protracted uncertainty, (2) that the project was reasonable through the project's duration in light of both the relative uncertainties that then existed and of the alternatives for meeting the service needs of the customers, (3) when the projects were cancelled, and (4) that they were cancelled promptly when the conditions warranted." (D.91-12-076, 42 CPUC2d 645, 688, quoting D.89-12-057, 34 CPUC2d 199, 269.)

Edison has not met its burden of proof in demonstrating cost recovery. We therefore deny Edison's request. First, Edison did not demonstrate that the project ran its course during a period of unusual and protracted uncertainty. In D.89-12-057, 34 CPUC2d at 268-269, we defined in more detail what we meant by periods of great uncertainty:

> "The exception is the product of the period of dramatic and unanticipated change, initiated most notably for utility planners by the oil embargo of 1973 and extending for almost a decade. The period was characterized by great uncertainty in the energy industry, both as to demand growth and availability of supply. During such a period, a reasonable utility management can still reduce risk, but not necessarily to a level at which the shareholder may be fairly be expected to absorb all the costs of cancelled projects. During such a period, the ratepayer should participate in the increased risk confronting the utility."

Edison stated that in April 1987 the investor-owned utilities filed the first COT project application which the Commission rejected as incomplete, and that in August 1990 Edison filed an application containing an economic analysis performed jointly with DRA. Accordingly, Edison argues that the lengthy

period of Commission review of its COT project application fulfills the criterion of a period of unusual and protracted uncertainty.

We disagree. The time between the filing of the two applications is not a period of unusual and protracted uncertainty because the Commission deemed the initial application incomplete, and filing a complete application was directly within Edison's control. We do not believe the time period between the filing of the completed application (August 1990) and April 1991 when the Commission denied Edison's participation in the COT project satisfies this criterion because the Commission issued its decision within the statutory period required for such applications under the Permit Streamlining Act, Government Code § 65920 et seq. (See D.91-04-071, 39 CPUC2d 615, 622.)

Edison has not met its burden of proof as to the second criterion. Edison states that (1) it offered evidence in its COT project application that the COT project was economically feasible; (2) the ALJ's proposed decision authorized Edison's participation in the COT project; and (3) only the Commission decision denied Edison's participation. Therefore, Edison argues that the project was reasonable during the pendency of its application before the Commission. However, other parties challenged the cost effectiveness of the COT project before the Commission, and Edison moved to exclude certain DRA studies on residual air emissions, which studies reduced the cost-effectiveness of the project. Although the ALJ granted Edison's motion to exclude the studies, the Commission found that applicants had not met their burden of proof on the cost-effectiveness of the project under PU Code §§ 701.1 and 1101 because there was no record on which to base a determination of residual environmental costs and benefits. (39 CPUC2d at 623.) Moreover, both the proposed and the Commission decision on the COT project found that Edison's participation in the project resulted in negative net present value benefits. The distinction was that the ALJ found these benefits insignificant, while the Commission found them significant. Because Edison's cost-effectiveness analysis was heavily disputed during the pendency of the COT project application and Edison did not meet its burden of proof on certain aspects of cost-effectiveness, we do

not believe Edison has met its burden of proof here that the project was reasonable during the pendency of its application because Edison believed the project was cost-effective.

Edison has met its burden of proof that the project was cancelled, but its conclusory allegation that it cancelled its participation in the COT project when the Commission denied the application provides a weak showing that Edison cancelled the project promptly when conditions warranted. However, it is unnecessary for us to address this criterion in light of our determination above.

Edison argues that we should grant this request because we permitted SDG&E and PG&E to recover their costs for the project. We disagree. Edison does not prove that its involvement in the project was similar to SDG&E's or PG&E's. For example, the Commission found SDG&E's participation in the COT project to be cost-effective, but denied participation at that time because SDG&E failed to satisfy the criteria of PU Code § 1102 and demonstrate the feasibility of negotiating long-term contracts for Northwest capacity at reasonable rates. (39 CPUC2d at 631.) Moreover, we approved SDG&E's recovery as part of a settlement of its general rate case application, which had its own set of tradeoffs and is not generally precedential in subsequent proceedings. (See Rule 51.8 of the Commission's Rules of Practice and Procedure.) PG&E's request for cost recovery in its last general rate case was not contested by any party, and as a practical necessity of our reviewing such voluminous applications, was subject to little if any review compared to that received by the contested issues. (See discussion on burden of proof in SoCalGas' test year 1994 general rate case, D.93-12-043, slip op. at p. 9.)

Edison also argues that because DRA did not identify a deficiency related to the COT project when Edison filed its NOI and no party presented testimony opposing Edison's request, Edison was somehow disadvantaged in meeting its burden of proof. DRA counsel extensively cross-examined the Edison witness on the COT project (R.T. Vol. 21, pp. 2490-2509). Edison could have presented sufficient redirect testimony to this cross-examination, which it did not. Although DRA's witness withdrew its COT project testimony

on advice of counsel. DRA's counsel indicated on record DRA's position, namely, that as a matter of law Edison had not met its burden of proof on this issue. (R.T. Vol. 39, pp. 4548-4550.)

It is not incumbent on DRA to identify every issue on which Edison has not met its burden of proof at the NOI stage. If so, the purpose of DRA's involvement at the evidentiary hearings would arguably be unnecessary. DRA has a compliance role at the NOI stage, i.e., to determine whether a utility's application complies with the rate case plan's "Standard Requirement List of Documentation Supporting an NOI." (See D.89-01-040, 30 CPUC2d 576, 582 and Appendix B.) In D.89-01-040, we made clear that we were "anxious to take advantage of DRA's expertise in determining completeness [of a utility's general rate case application] without confusing the distinction between the compliance function and DRA's role as an active party in the forthcoming case." (Id.) Also, TURN opposed Edison's recovery on this issue and TURN had no involvement at the NOI stage. In conclusion, we find Edison has not met its burden of proof on this issue, and therefore deny its request for recovery of its share of costs for the COT project.

9. Electric Distribution

The differences between Edison and DRA in this category prior to settlement focused on the differences in their respective estimates on customer growth. At the evidentiary hearings before the settlement, TURN raised several issues. The settling parties adopted Edison's position on these issues.

9.1 O&M

9.1.1 Customer Growth Impact

Several of TURN's recommended decreases to Edison's test year expenses also occur because of a difference in customer growth estimates. We resolve the customer growth issue above and make the appropriate changes to certain distribution accounts.

9.1.2 Overhead Line Operations

TURN recommended that the Commission reduce Account 583.400 by $797,000 so as to normalize the fluctuating costs of pole inspections. TURN argued that when the low level of actual pole inspections for 1992-1994 is averaged with the projected number of pole inspections for 1995-1997, it results in 57,000

annual pole inspections. TURN argued that Edison should receive for its test year only an amount determined by multiplying the 57,000 annual pole inspections by Edison's estimated cost of inspection. TURN did not believe that this normalizing would compromise system reliability, since Edison received monies to conduct about 90,000 pole inspections between 1992-1994, and instead conducted 8,821, and that its recommended methodology normalizes costs over a six-year period to reflect the volatility of Edison's pole inspection program.

Edison stated that TURN's recommendation would result in higher maintenance costs in the future, degradation of system reliability, and a reduction in safety, since TURN's recommendation necessarily would mean that Edison would have to reduce the number of pole inspections. Edison argued that its 1992 general rate case application did not break out its funding request into subaccounts, and therefore Edison did not identify the number of pole inspections planned or funded in the 1992 general rate case.

Edison's argument that it cannot be determined how many pole inspections were planned and funded in the 1992 general rate case cycle does not speak to the issue of why it conducted only 8,821 pole inspections between 1992-1994, yet it plans to conduct approximately 113,000 per year for the next three years. Nonetheless, Edison does demonstrate the importance of timely pole inspections in order to take advantage of cost-effective life-extending methods for treating poles. Because of overriding safety considerations, we deny TURN's recommended reductions.

Because of the safety concerns articulated by Edison, we wish to insure that necessary pole inspections occur. We have similar concerns with respect to Edison's inspections of underground structures. (See Section 9.1.3 below.) Therefore, beginning in 1996 and ending in 1998, Edison should file an annual report no later than March 1 of each year indicating (1) the number of pole inspections and inspections of underground structures

has conducted in the prior year and (2) the number of pole inspections and inspections of underground structures it forecasted in its general rate case testimony for that year. This report should be filed with the Commission in this docket and served on the Commission Advisory and Compliance Division (CACD) as well as all parties to this case. If at the end of any year Edison has failed to meet its targeted (i.e., forecasted) goals, we will consider imposing penalties on Edison for compromising safety of its distribution system.

9.1.3 Underground Operations and Maintenance of Underground Lines

TURN raised the same concerns in these accounts (Accounts 584.4 and 594.3) as it did in Account 583.400. For the same reasons we discuss above, we deny TURN's recommended reduction to these accounts.

9.1.4 "Turn On/Off Services"

TURN recommended reducing Account 586.100 to capture efficiencies in establishing service based on the practices of other utilities which TURN believes Edison has not yet incorporated into its own practices. Because our resolution of the issue of increasing the service establishment charge (see Section 10 below) takes this recommendation into account, we deny TURN's request here.

9.1.5 Meters In/Out

Edison has identified Account 586.200 to capture the cost of installing, removing, rearranging, and retiring electric meters. TURN recommended reducing this account by about $75,000 to reflect a difference between Edison's witness' testimony and his workpapers. On rebuttal, Edison's witness acknowleged that the incorrect workpapers were inadvertently included with Edison's original testimony, but stated that the estimate in its proposed testimony was correct, and included the correct workpapers for this subaccount. We reject TURN's proposed reduction.

9.1.6 EMF Expense Estimates

TURN recommended a reduction of $23,000 to Edison's electromagnetic fields (EMF) expense estimates which Edison has agreed to. We approve this reduction.

9.2 Capital Costs

9.2.1 Cost Per Customer Multiplier

Edison and DRA agreed that a multiplier of $1,719 in constant 1993 dollars is an appropriate multiplier to determine the distribution capital cost per customer. No other party opposes this multiplier, which we adopt.

9.2.2 Streetlight Acquisition Program

Edison's distribution line capital expenditures request includes funding for acquisition and upgrading of customer-owned streetlight systems, a portion of which is offset by customer contributions from participating cities.

There are close to 670,000 streetlights in Edison's service territory, of which Edison's customers own about 180,000. About one third of the customer-owned lights are connected to series circuits, an old-fashioned setup which is both more costly and less efficient compared with lights configured under modern multiple circuits. The principal disadvantage of series circuits is the regulated output (R.O.) transformer needed for this arrangement. In addition to being obsolete (and thus expensive to maintain), the constant current required by R.O. transformers makes them inefficient. Edison-owned lights are served on rate schedule LS-1; customer-owned lights are served primarily on schedule LS-2.

In recent years, over 20 cities have approached Edison to discuss selling their streetlight systems. In addition, the decision in the rate design phase of Edison's last general rate case, (acting on a request from CAL-SLA) ordered Edison to report in this rate case on the outcome of efforts undertaken with streetlight customers to evaluate options for replacing series circuits. (D.92-06-020, 44 CPUC2d 471, 555.) Edison stated that

it responded to these customer requests and to our order in the general rate case by developing plans to buy over 50,000 streetlights. About half of these are series lights, which Edison plans to upgrade to multiple circuits. Edison also intends to replace incandescent and mercury vapor lights with high-pressure sodium vapor (HPSV) lamps. The majority of the upgrade costs will be funded through city contributions, the balance through the LS-1 tariff.

9.2.2.1 Positions of Parties Prior to Settlement

CAL-SLA

CAL-SLA was the only party to voice opposition to Edison's program, arguing that it does not comply with D.92-06-020. CAL-SLA stated that Edison had no follow-up contact with it since two initial meetings in 1992, and did not explain its failure to schedule additional meetings. Claiming that Edison's acquisition program is just a marketing plan to buy streetlights (multiple as well as series), CAL-SLA was particularly concerned about the potential impact on nonparticipants, asserting that the balance of program costs over and above the cities' contributions will be collected from either all customers or all the LS-1 customers. According to CAL-SLA, Edison's own figures show that the incremental costs of the program exceed incremental revenues. Moreover, based on Edison's rebuild costs for the previously acquired Los Angeles County streetlight system, CAL-SLA believed Edison understated the true cost. Most importantly, the streetlight program does not address the reason CAL-SLA raised the issue in the last general rate case, which was to reduce local governments' streetlight bills. CAL-SLA stated that LS-2 multiple customers will see their bills increase considerably, while a typical LS-2 series customer will receive only about a 5% decrease.

CAL-SLA suggested that Edison missed several possible alternatives to its streetlight program, including funding through DSM; Edison's tariff Rule 20-A (which governs the undergrounding of

overhead facilities) for the CEC, and using retrofit kits to upgrade incandescent and mercury vapor lamps to HPSV.

Edison

Edison responded that CAL-SLA misconstrued its streetlight program. According to Edison, CAL-SLA apparently believed the expenditure for upgrades is simply to replace incandescent and mercury vapor lights with HPSV; however, this funding is to convert series lighting to multiple and all lamp types to HPSV. The use of retrofit kits to upgrade to series HPSV is therefore impractical, since the series R.O. transformers are incompatible with series HPSV lighting. Incremental program costs exceed incremental revenues due to the elimination of a current subsidy from LS-2 series customers,[31] but the subsidy vanishes due to the very process of converting from series to multiple, not because of Edison's acquisition program (and thus the same result would obtain if cities converted on their own in the absence of Edison's program). Contrary to CAL-SLA's claim, program costs were not understated, because the Los Angeles County acquisition was uniquely expensive.

Edison argued that CAL-SLA's concern that other customers will be disadvantaged is unfounded, because the LS-1 tariff already includes a component that allows Edison to recover its capital investment in streetlights. Edison explained that its per-lamp acquisition cost recovered under schedule LS-1 is capped at the "wood pole equivalent" cost, which is the same for new or used streetlights. The acquisition program thus does not differ in principle from the installation of a brand new streetlight system in a newly incorporated city, and Edison's investment in the

31 This subsidy results from the happenstance that levelized rates presently exceed the true depreciated revenue requirement.

program will be recovered through the LS-1 bills of participating customers.

Edison stated that CAL-SLA did not provide sufficient evidence on avoided ownership and maintenance costs to substantiate its claims of rate inequities and deleterious customer bill impacts. Contrary to CAL-SLA's claims, Edison did examine and rejected as infeasible several program alternatives. For example, streetlight acquisition does not qualify for DSM funding, principally because the associated energy savings are incidental to the program, which is motivated primarily by cost considerations. Edison also stated that its tariff Rule 20 A does not apply, and CEC funding is unlikely.

9.2.2.2 The Settlement

As CAL-SLA did not join the settlement, and DRA took no position on Edison's streetlight program, the settlement assumed Edison's funding request on this issue.

9.2.2.3 Discussion

D.92-06-020 did not order Edison to meet with CAL-SLA, but adopted CAL-SLA's own request that Edison meet with its streetlight customers and report on the outcome, both of which Edison has done. Edison, moreover, has independently responded to requests from streetlight customers to acquire and upgrade their systems, whether series or multiple. Edison's acquisition program appears to fulfill its obligation to serve LS-2 customers desiring to migrate to Schedule LS-1.

CAL-SLA contended that the revenue requirement associated with this program will be collected from either all customers or all the LS-1 customers. With respect to the former, it has long been our policy to treat streetlight facilities charges as nonallocated revenue, directly assignable to the streetlight

class.[32] Thus, barring some undetected problem in the revenue allocation process, other customer classes should not be impacted. With regard to the latter, Edison has explained that the capped "wood-pole equivalent" capital recovery component of the LS-1 tariff insures that only participating LS-1 customers will absorb the costs of this program (with cities' contributions covering the balance over and above the wood-pole equivalent rate). This explanation has intuitive appeal and was not specifically refuted by CAL-SLA.

Qualitative reassurances notwithstanding, Edison's witness stated that he was not intimately familiar with the LS-1 tariff; moreover, he acknowledged "there may be some complexity from a rate design perspective that you might want to address in Phase 2." (R.T. Vol. 5, pp. 588-604.) Accordingly, Edison should quantitatively demonstrate that all components of the program's revenue requirement (including return on rate base, franchise fees and uncollectibles, etc.) will be borne only by participating LS-1 customers (and to take appropriate corrective rate design measures as needed). We therefore conditionally approve Edison's streetlight acquisition program, pending such a demonstration which Edison should make in this proceeding no later than February 29, 1996. If the filing is contested, the issue should be resolved in Edison's next rate design window proceeding or other appropriate forum as determined by the assigned ALJ.

32 D.86-08-083, 21 CPUC2d 613, 642-645; D.87-12-066, 26 CPUC2d 392, 532-533.

10. Customer Accounts Expenses and Proposed Customer Service Charges

10.1 Meter Reading Expense

10.1.1 Positions of Parties

Prior to the Settlement

DRA recommended cutting Edison's $25.519 million funding request to $15.305 million, a reduction of $10.214 million. This reduction consists of two components. First, DRA suggested the Commission adopt an imputed savings of $10 million (roughly 40%), since Edison "may choose to contract out its meter reading and may obtain significant savings." DRA noted that SoCalGas had recently solicited bids for meter reading contracts and subsequently challenged its employee union to match the lowest bid: a 45% cost reduction. Second, DRA advocated normalizing over 1995-1997 the savings from Edison's remote meter reading program. This would save an additional $0.214 million.

Edison replied that DRA's plan would double-count savings which Edison has already achieved. Edison stated that SoCalGas' most important cost-cutting program is the redesigning of its meter reading route time standards, a measure which mimics Edison's own such standards, and which according to Intervenor Unions' testimony (Exhibit 716) is by itself projected to increase SoCalGas' meter reading productivity by 31.55%. Second, Edison noted that from 1986 to 1992, its meter reading costs remained almost flat, while its meter count rose 14.4%, and labor and associated costs rose 25%. Moreover, DRA ignored Edison's efficiency-improvement initiatives (Exhibit 25). Third, Edison's operations are fundamentally different from SoCalGas's, making cost reductions inherently easier for the latter: Edison's service territory has a much lower customer density (since it encompasses a greater percentage of rural land), and its meters are less accessible and often (due to time-of-use pricing) considerably more complex to read -- points which DRA specifically acknowledged (Exhibit 402).

Fourth, Edison believes DRA did not take into account the high level of its meter reading performance (ranked fourth out of nineteen electric utilities in a recent national study), nor did DRA consider the tradeoff against increased customer costs (from expensive follow-up contact due to meter reading errors) should an outside contractor not perform as well. Finally, Edison objected to normalization of 1995-1997 remote meter reading savings in the absence of a comparable normalization of costs.

Intervenor Unions argued that DRA's proposal would contravene their long-standing collective bargaining agreement with Edison. They also disputed DRA's claim that SoCalGas' unit meter reading costs were substantially lower than Edison's prior to its bid solicitation.

<u>The Settlement</u>

The Settlement adopted Edison's positions on both counts. (Settlement Joint Comparison Exhibit at pp. 28-29.)

<u>10.1.2 Discussion</u>

Edison has adequately justified its cost-containment measures for this category of expenses; there is no record basis to adopt $10 million in imputed cost savings. The normalization issue is identical to the controversy discussed in Section 20 (Capitalized Software). Based on that discussion, we reject DRA's recommended $0.214 million reduction.

On another issue, Edison presented evidence regarding the unit revenue requirement of special metering equipment for use in Phase 2 of this general rate case pursuant to Ordering Paragraph #2 of D.93-07-030. (<u>See</u> Exhibit 24, (pp. 121-124).) Edison's estimates were uncontested, appear reasonable, and should be adopted.

<u>10.2 Customer Service Charges</u>

<u>10.2.1 Parties' Positions</u>

In its original testimony, Edison proposed increasing other operating revenue from $14.2 million in 1992 to $42.9 in 1995 by adding a residential late payment charge on delinquent accounts

and by changing or increasing other charges and fees. Specifically, in addition to the late payment charge, Edison proposed to increase its (1) service establishment charge (from $10 to $25 for same day service, and from $5 to $15 for next day service); (2) reconnection charge (from $15 to $25 for same day service, from $10 to $15 for next day service, and a $30 charge for reconnections which occur after business hours or on weekends. For reconnections at the service drop, Edison proposed charges of $30, $50 and $60 for next day, same day, and weekend or after-hour service respectively); (3) returned check charge (from $5 to $10); and (4) discontinue the $5 field collection charge, but add a new $15 field assignment charge, which would charge not only for field collections, but also such items such as service disconnections and field extensions.[33] Edison argued that the purpose of all such charges is to recover costs from those customers who incur them, and to unbundle these charges to provide a price incentive to customers to reduce these costs. Edison's specific justification for individual service charge increases or implementation is discussed more fully below.

In its original testimony, DRA disagreed with the amount of Edison's proposed service establishment charge and recommended increasing that charge to $15 for both the same day and next day service. DRA also opposed the new field assignment charge on the grounds that separating additional activities and charging for each one unduly increases the burden to pay on those who can least afford it. DRA proposed maintaining the field collection charge but increasing it from $5 to $10. In the settlement, DRA agreed

33 Edison originally proposed that the new field assignment charge also apply to the delivery of 48-hour notices, but withdrew this proposal after consultation with TURN.

with Edison's position on all of these charges in order to obtain the overall benefits of the settlement.

TURN originally opposed the implementation of the new late payment charge and field assignment charge, as well as the increased charges proposed by Edison for the other services listed above. TURN generally argued that now is not the time to add to the financial burden faced by Edison's residential customers, especially those that are most financially at risk. TURN requested that the Commission defer implementation of these charges at least until the economic conditions in Edison's service territory improve and Edison has sufficiently studied the impact of its proposed changes on low-income customers.

TURN argued that the Commission should balance many factors besides Edison's cost of customer services in order to determine the appropriate charges. The Commission should also consider (1) the current economic conditions in Edison's service territory, which includes high unemployment (running fully three percentage points higher than the national average), (2) that residents have endured civil unrest and many natural disasters, and (3) that government assistance programs have suffered cuts, while other costs, such as rents, are quite high (with the fair market rent for a two-bedroom apartment about 150% of the typical AFDC grant for a family of three). Furthermore, TURN stated that the proposed service charges will fall disproportionately on low income customers. For example, 13% of reconnections were performed for Low-Income Ratepayer Assistance (LIRA)[34] customers even though those customers made up only 8% of all residential customers. TURN also stated that the customer service charges should be set at a

34 LIRA is now called California Alternate Rates for Energy (CARE).

level to provide Edison with an incentive to achieve greater efficiencies in its costs for providing these services.

In its original testimony, TURN alternatively proposed different increases from Edison to several of the customer charges, in the event the Commission determined it appropriate to increase certain charges. These increases include (1) $9.00 for the returned check charge; (2) increasing the reconnection charge by 25% (resulting in a charge of $12.50 for next day service and $18.50 for same day service); and (3) a charge of $7.50 for the field assignment charge. TURN continued to oppose increases to the service establishment charge and instituting a late payment charge. In its testimony on the settlement, TURN supported its alternative proposal.

At the hearings prior to the settlement, Cal/Neva opposed increasing the service establishment charge and adding a late payment charge. Cal/Neva also pointed to the trying economic conditions in Southern California, and stated that these service charge increases would make it more difficult for low-income customers to obtain and maintain utility service. Cal/Neva argued that the impact of increases to the service establishment charge would more adversely impact low-income customers and the working poor, because the majority of low-income people are renters who move more frequently than homeowners (and thus will pay the service establishment charge more often). Cal/Neva's witness also stated that nonprofit agencies would be impacted by these charges, since nonprofit agencies which provide low-income emergency energy assistance programs in Edison's service territory report that at least 60% of the total funds they have available are paid to Edison.

In rebuttal, Edison argued that these proposed service charges would reduce the net revenue requirement to all other customers by about $42 million, and would also motivate customers

to avoid the proposed higher credit-related charges, thus benefiting all customers.

10.2.2. Discussion

We discuss Edison's requested customer service charge increases and additions individually below.

Service Establishment Charge

Edison proposed to increase its service establishment charge from \$10 to \$25 for same day service, and from \$5 to \$15 for next day service, based upon its costs for these services.

Determining the costs certain customers impose upon the utility system is one factor in determining the appropriate level of the service establishment charge. In SoCalGas' test year 1994 general rate case, D.93-12-043 (slip op. at p. 43) we reasoned that "[c]harging customers rates that are less than the costs imposed for establishing service results in the cross-subsidization of those who move (establish service) by those who do not move or who move less frequently."

However, cost is not the sole factor relevant to our inquiry. As we stated in D.91-12-075, 42 CPUC2d 566, 591-592:

> "Our past decisions have never held that just and reasonable rates, the statutory standard (PU Code §§ 451 and 728), had only one component - costs. We have always held that factors such as conservation, affordability, market price, and equity had to be factored into the rates. Cases which most strongly supported cost-based rates invariably tempered those statements with language which showed our concern for other ratemaking factors.
>
> "A reading of the PU Code leaves no doubt that the Commission must look beyond costs when setting rates. ...There is nothing in the Code which equates cost-based rates as being a synonym for just and reasonable rates, or as

the sole standard by which rates are considered just and reasonable." (Citations omitted.)[35]

In D.91-12-075, we further stressed that in exercising our ratemaking function, we balance many factors in order to determine the most appropriate rate. "A careful reading of the Code will show more exceptions to cost-based ratemaking and more reasons why ratemaking is an exercise in judgment and not the result of a computer printout." (Id. at p. 592.)

In D.93-12-043, we increased SoCalGas' service establishment charge to $25, and provided for a reduced rate of $5 for LIRA-eligible customers to help mitigate hardships of this increased rate. However, in D.93-12-043, SoCalGas demonstrated cost efficiencies in service establishment, for example, by the implementation of a soft-close policy for establishing service.

Here, TURN argued that Edison has not demonstrated cost efficiencies in service establishment. TURN reasoned that if the service establishment charge is increased, it should not be as great as Edison requests, in part, because Edison should be investigating more efficient procedures for reducing the number of field service visits to establish service, citing as examples the methods employed by SMUD and PG&E. Edison stated that it is engaged in a pilot study on leaving the meter energized but turning it off at the main breaker, in order to avoid additional service calls. Additionally, Edison stated it believes that although it is studying the issue, a soft close policy would probably not be appropriate for its entire service territory, although it might be implemented selectively.

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35 Although the section cited from D.91-12-075 involves a dispute in SoCalGas' biennial cost allocation proceeding over allocation of interstate pipeline demand charges, the Commission's general ratemaking language is equally relevant to the customer service charge issue.

After balancing the economic policy of charging a customer for the costs incurred against the economic conditions in southern California, and the fact that an increase in the service charge would disproportionately impact low-income customers, we are reluctant to impose as high a service establishment charge as Edison suggests. We also balance the fact that Edison has not demonstrated it has fully investigated and implemented appropriate cost efficiencies in this area. We wish to encourage Edison to find more efficiencies in this area.

We therefore permit Edison to increase its same day service establishment charge from $10 to $17.50, and to increase its next day service establishment charge from $5 to $10. We find this an appropriate balance so that customers might pay closer to Edison's costs, but that Edison also might gain more efficiencies. Edison argued that providing for a special LIRA service establishment charge would cause increases in administrative costs. In light of the fact that our next day service establishment charge is $10, we do not impose a special LIRA rate. However, if the charge was any higher, we would do so. (See e.g., D.93-12-043.)

Reconnection Charges

For the reasons discussed above with respect to service establishment charges, we approve an increase in Edison's reconnection charges for same day service from $15 to $20 and a $25 charge for after hours or on weekends. We also approve charges of $30, $50, and $60 for reconnection charges at the service drop for next day, same day, and weekend or after hours service respectively. Edison's reconnection charges for next day service are increased from $10 to $12.50.

Field Assignment Charge

For the reasons discussed above with respect to service establishment charges, we approve Edison's implementation of a field assignment charge which subsumes Edison's current field collection charge. Additionally, Edison would also bill customers

for the field assignment charge for field extensions and service disconnections. However, for the reasons discussed above, we adopt $10 for the field assignment charge instead of Edison's recommended $15.00.

Returned Check Charge

Edison currently charges $5 for a returned check charge, but requests an increase to $10 to cover its actual costs. The record established that Edison's actual costs for returned check charges in 1995 dollars is $9.01 per check.[36] We therefore authorize Edison to increase its returned check charge to $9.00.

Late Payment Charge

Edison stated that the Commission should approve its late payment charge so that customers who do not pay their bills on time should bear the working cash financing costs. TURN and Cal/Neva opposed this new charge on the general grounds discussed above. Additionally, TURN cited to problems in the way Pacific Bell implemented its late payment charge, and argued that Edison's method for implementing the charge could also pose similar problems. For example, TURN stated that Edison currently treats payments as "received" based on the payment processing date, not the actual date of receipt, and that a computer system to override the processing date with the receipt date is not expected to be in place until approximately early 1997. TURN argued that, although in the majority of cases the processing and receipt date will be the same, a problem could occur from payments received at an authorized late payment location (APL), where, according to

36. Edison's $10 charge included bank costs for checks which did not clear on the first attempt but did clear on the second attempt. We believe it is more appropriate to assign those costs to the general body of ratepayers (i.e., overhead) than to have specific customers who bounced checks pay for costs which they did not incur.

Edison's own study, 16% of the payments from the APLs were received with a lag of at least six days. TURN also argued that if the late payment charge is approved, it should not apply to bills less than $40.

Edison argued that it has taken safeguards to ensure that similar problems to those of Pacific Bell would not occur. For example, Edison stated that it would institute a five day grace period before payments were termed late. Additionally, Edison would have the APLs mail customer payments daily, and would provide the means for correcting any errors which come to its attention. Furthermore, payments from APLs account for less than 5% of payments. Edison objects to TURN's suggestion that the charge not apply to bills less than $40.

In requesting that we approve a late payment charge, Edison is requesting approval of a new residential customer charge, rather than an increase of a current customer charge. We deny Edison's request to implement a late payment charge at this time. In reaching this decision, we take into consideration (1) the current state of the southern California economy and (2) the fact that a more advanced computer system, which would override the processing date with the receipt date, will not be operational until approximately early 1997. We would be willing to reconsider this decision when the economy has significantly improved and Edison's more advanced computer systems are operational, since it appears that improved capability for proper recording of the payment receipt date should resolve many of TURN's payment processing concerns.

In order to determine its working cash requirement, Edison decreased the average number of lag days for its residential class by 1-1/2 days due to its proposed late payment charge. (See Exhibit 45, at p. 162.) Since we do not approve the late payment charge, the average number of lag days for Edison's residential class estimate should be increased by 1-1/2 days in order to

determine its working cash requirement. This adjustment appears in the tables attached to this decision.

TURN's BRAM Proposal

Edison's customer service charges are currently treated as other operating revenue for ratemaking purposes. TURN was concerned that actual revenue may differ from the forecast due to forecasting error, and therefore recommended balancing account treatment under BRAM to compensate for any forecasting error. Edison disagreed, arguing that if the number of reconnections increased (thereby increasing the projection of revenues for the reconnections), then Edison's costs for reconnections would also increase from the costs forecast in the general rate case. Because an increase in customer service activities should cause an increase in cost to the utility as well as an increase in operating revenue, we decline to adopt TURN's BRAM proposal.

10.2.3 Edison's Petition for Modification

Edison petitioned to modify our Interim Decision in order to be permitted to implement the revisions of the customer service charges and added facilities charges as proposed by the settlement on an interim basis. In that decision, we did not authorize Edison to do so because this could be viewed as prejudging a policy issue which was strongly contested at hearings. Additionally, we stated that implementing interim service charges which could be changed in a later decision could increase ratepayer confusion and add costs in providing the affected ratepayers with a refund and an explanation for the inconsistent treatment. We also stated that to the degree Edison does not realize the full benefit of its changed tariffs for both customer service charges and added facility charges before further Commission decision, this was a risk that Edison assumed by filing a late settlement with the Commission. We see no reason to reverse our initial determination and deny

Edison's petition for modification of the Interim Decision, D.94-12-045.[37]

11. Customer Service and Informational (CS&I) Expenses

11.1 Overview

In this section, we address Edison's request for DSM and certain other funding items which Edison has classified as CS&I expenses. The settling parties propose $471.2 million for Edison's DSM program and $23.9 million for O&M activities. This results in an $84 million reduction to the DSM budget from Edison's position at the conclusion of the evidentiary hearings. No party other than the settling parties supports the settlement. In this section we describe our adopted funding levels for these activities which differ significantly from those proposed by the settling parties.

The settling parties have failed to present an analysis of the long-term ratepayer effects of this major reduction of the DSM budget. Instead, they appear to have forgone significant long-term ratepayer benefits for a short-term revenue reduction. We believe our adopted budget for the activities requested in this area provides a better balancing of ratepayer interests than the settlement.

Several parties state that § 701.1 is pertinent to our determination of the appropriate level of DSM funding. PU Code § 701.1 provides in pertinent part that:

> "(b) The Legislature further finds and declares that, in addition to any appropriate investments in energy production, electrical and natural gas utilities should seek to exploit all practicable and cost-effective conservation and improvements in the efficiency of energy use and distribution that offer equivalent or better system reliability, and

37 We also deny CSB's petition for modification of this decision. (See Section 16 below.)

which are not being exploited by any other entity."

In interpreting § 701.1, we have stated that this section "must be considered 'in addition to other ratepayer protection objectives,' as stated in § 701.1(a) itself." We added that the "practicality test in § 701.1 includes the practicality of Commission review of DSM funding by ratepayers." (See D.91-12-076, 42 CPUC2d at 733-734.) We have also held that notwithstanding § 701.1, a utility must meet its burden of proof in justifying its DSM request.[38]

Another § 701.1 limitation on a utility's DSM programs is the extent of exploitation of conservation by other entities. "Market players are among the other entities specified by § 701.1, confirming Edison's conclusion that § 701.1 does not require ratepayer funding of every dollar needed to achieve all cost-effective energy conservation." (D.91-12-076, 42 CPUC2d at 734.)

We authorize a total of $71.1 million for Edison's DSM programs and a total of $9.65 million for Edison's CS&I and Sales O&M programs. (See the chart following Section 11.4 which sets forth a breakdown of the funding levels we approve.) Although this is a reduction from 1992 funding levels, we believe that this is an appropriate level of funding based on the evidentiary record as more fully set forth in each category below. Because of the pendency of the electric industry restructuring proceeding (R.94-04-031, I.94-04-032), there exists some uncertainty regarding the role of the utility in DSM (i.e., what types of DSM activities

38 "The requirement is that the utility seek to exploit all 'practicable' and 'cost-effective' opportunities. Unless PG&E meets its burden of proof to justify its proposed expenditures, we cannot conclude its proposals are either practicable or cost-effective." (D.91-12-015, 42 CPUC2d 238, 251.)

utilities or competitors will be pursuing, how DSM will be funded, etc.) We authorize a DSM budget which provides for substantial utility commitment to DSM in the face of uncertainty. The budget we adopt does not necessarily align with the settling parties' or any other party's specific dollar recommendations. Consistent with the policy articulated above, we apply our overall judgment in determining the appropriate level of DSM for each category. For example, our budget provides more services to residential customers than the settlement, while not reducing services to nonresidential customers. Moreover, we emphasize project areas which promote long-term savings. Our DSM budget also provides Edison with additional flexibility to work within its budget constraints to design the most cost-effective program to serve its customers. We believe that appropriate program design should allow Edison to maximize the savings per dollar spent, drawing on its experience operating DSM programs and the expertise of its Advisory Committee.

Furthermore, we note that for the portion of the DSM budget subject to two-way balancing account treatment, the utility is able to spend up to 130% of authorized budgets for resource programs. (See D.94-10-059.) In this respect, we encourage Edison to aggressively pursue other cost-effective DSM opportunities.

In addition, we do not exempt Edison's requested ratepayer funding of activities that cause DSM impacts from scrutiny under our DSM rules, simply because Edison has changed the name or accounting treatment of certain activities. Consistent with our pronouncement in past decisions, changes to our DSM rules should be raised in R.91-08-003/I.91-08-002 (the DSM Rulemaking/Investigation). (See e.g., D.92-12-057, slip op. at pp. 192a-193; D.91-12-076, 42 CPUC2d at 719, 730.)

11.2 Background

The FERC Uniform System of Accounts sets aside Accounts 906 through 910 for costs associated with CS&I activities whose object is to encourage safe, efficient and economical use of the utility's services. In Edison's 1992 general rate case, all of the funding in these accounts appears to have been authorized for the development, implementation, and monitoring of energy efficiency and DSM services. In its original testimony in this

rate case, Edison has also requested funding for certain activities which it classifies as non-DSM CS&I costs. The settling parties expanded this request for O&M funds. Because Edison has requested funding for these O&M activities as part of the CS&I budget, we have reviewed the definitions of the various FERC accounts and have determined that funding for certain requested activities is more appropriately accounted for in Accounts 911 through 917 as set forth below.[39]

In Edison's 1992 general rate case, all of Edison's DSM funding was subject to one-way balancing account treatment. In this rate case, Edison proposed its requested O&M funding not be subject to balancing account treatment, but instead be treated in the same manner as O&M expenses.[40] We require Edison to establish a two-way balancing account for its retrofit and new construction programs in order to implement its funding flexibility. This requirement is consistent with our shareholder incentive decision (D.94-10-059), which authorized Edison to spend up to 130% of authorized budgets for resource programs. This would make our treatment of Edison consistent with our treatment of SoCalGas, PG&E and SDG&E. We address the appropriate balancing account treatment for Edison's requests herein.

We have approved funding for certain programs which should be assigned to FERC accounts other than the CS&I accounts. In addition, we have adopted a funding level which differs from that proposed by Edison, DRA, the settlement, or by any other party. Rather than guess at which costs belong in which FERC account, we order Edison, after meeting and conferring with interested parties from this proceeding and its Advisory Committee,

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39 FERC Accounts 911 through 917 are set aside for activities whose object is to promote or retain the use of utility services by present and prospective customers, also called sales expenses.

40 Under one-way balancing account treatment, funds which are not spent on authorized DSM activities are returned to the ratepayers and overexpenditures are borne by the shareholders. Two-way balancing account treatment allows the utility to exercise authorized funding flexibility.

to file an Advice Letter which assigns the adopted funding to the proper FERC accounts. This Advice Letter should be filed within 60 days of the effective date of this decision. If the parties do not reach consensus, the Advice Letter should state Edison's preference, as well as all alternative positions of other parties.

11.3 Summary of Request

Edison originally requested a test year 1995 budget, in 1992 dollars, of $138.8 million for its DSM programs, and $11.1 million for O&M activities.[41] Edison's authorized DSM budget for test year 1992, in 1992 dollars, was $140.86 million. Edison's original budget request was separated into the following categories:

Table 11-1
Requested Test Year CS&I Budget
(1992 $ Millions)

Category	Amount
Conservation and Energy Efficiency	103.8
Load Management	7.3
Fuel Substitution	1.5
Load Retention/Load Building	2.2
Measurement, Forecasting, and Regulatory Reporting	19.3
Other DSM	4.7
Subtotal DSM	138.8
O&M	11.1
Total CS&I	149.9

The settling parties request a test year 1995 budget, in 1992 dollars, of $47.2 million for DSM programs, and $23.9 million for O&M activities.

41 Within the requested $11.1 million for O&M funding is $5.8 million requested for Economic Development activities. Funding for Economic Development programs is addressed in Section 12 of this decision.

Table 11-2
Settlement Test Year CS&I Budget
(1992 $ Millions)

Conservation and Energy Efficiency	34.7
Load Management	1.3
Fuel Substitution	0
Load Retention/Load Building	0
Measurement, Forecasting, and Regulatory Reporting	9.3
Other DSM	1.9
Subtotal DSM	47.2
O&M	23.9
Total CS&I	71.1

11.4 Rules Governing Customer Service and Informational Expenses

Before addressing the specific program areas, we note that most of the debate among the parties reflects differences in opinion on what level of ratepayer-funded activities serve the ratepayers' longer-term interests. Before 1992, broad DSM policy considerations were litigated and resolved in each utility's general rate case proceeding regarding the types of activities which should be funded. We now have established rules which ratepayer-funded programs with DSM effects must meet. As we discussed in D.92-02-075, we issued the DSM Rulemaking/Investigation in order to create a consolidated forum for addressing DSM policy and methodological issues. Many of the parties in this case are active participants in that proceeding.[42]

We recognize that changing market circumstances require us to provide utilities with more operational flexibility in order to meet changing customer needs. Accordingly, we apply our DSM rules to Edison's specific funding requests in this proceeding with

42 We adopted our initial DSM rules in D.92-02-075. These rules and associated definitions have been augmented in subsequent decisions in the DSM Rulemaking/Investigation. The most recent version of the rules is contained in D.95-06-016.

an eye toward increasing utility management flexibility and minimizing regulatory micro-management. We recognize that with the recent shareholder incentive decision, the Commission's approach has been to shift performance risk onto shareholders and remove it from ratepayers. Consistent with this shift, it seems reasonable to provide utilities with the flexibility to effectively manage this risk and maximize the benefits associated with ratepayer-funded DSM programs. Where interpretation of the rules is necessary, we will apply our judgment in a manner that is consistent with the overall policy objectives of the rules.

Consistent with the purpose of the DSM Rulemaking/Investigation, we will not consider changes to our rules in this proceeding. To do so would frustrate several years of policy development in our Rulemaking and Investigation, and would clearly be unfair to all the active participants in that proceeding.

Before addressing Edison's specific funding requests, we provide a brief overview of our DSM rules.[43] Our DSM rules establish that the longer-term interests of ratepayers are best served by focusing ratepayer-funded activities with DSM impacts on programs that serve as least-cost, environmentally sensitive alternatives to supply-side resource options. Accordingly, the rules place ratepayer funding priority on programs which promote energy efficiency. In evaluating funding proposals which result in DSM impacts, the rules require the consideration of nonprice factors (e.g., environmental impacts), consistent with the consideration of those factors in utility supply-side procurement.

43 This discussion constitutes a very brief overview. A reader interested in a more detailed presentation of the rules should consult D.95-06-016 for the most recent version of the DSM rules.

Our rules identify the total resource cost (TRC) test as the primary test of program cost-effectiveness because only this test can measure the resource benefits to ratepayers from avoiding or deferring more expensive supply-side options. However, strict adherence to this test is not required for Direct Assistance Programs because they focus on equity concerns, rather than on the timing or type of resource needs of the utility. Similarly, strict adherence to the TRC test is not required for Information Programs and Energy Management Services, since the link between these programs and savings is difficult to measure. New Construction Programs must pass the TRC test for the program as a whole, but individual measures or program elements that do not not involve fuel substitution need not indicate TRC cost-effectiveness. This is because New Construction Programs also serve to promote the development of future, higher efficiency standards, in addition to providing resource benefits. Relatively high rebate levels may be required for some individual New Construction Program measures in order to achieve this goal.[43]

To ensure that environmental impacts are considered in making resource choices, Rule 7 directs the utilities to include the nonprice factors developed for supply-side resources in their cost-effectiveness analyses of DSM programs. The rules for evaluating and funding Fuel Substitution Programs echo these policies. Rule 13 makes it clear that programs to promote fuel switching will be funded if (1) they are cost-effective from a total resource and utility cost perspective (i.e., pass the TRC and Utility Cost test (UC tests)), (2) they are efficient in terms of the British thermal unit (Btu) consumption of the fuel source, and (3) they do not degrade the environment (the "three-prong test").

In developing Rule 13, we also stated that ratepayers should fund fuel-switching only to the extent that fuel-substitution technologies increase net total resource benefits relative to the most-efficient, available, same-fuel technologies. Accordingly, in applying the three-prong test, proponents of Fuel Substitution Programs must compare the technologies offered by

their program with the most efficient same-fuel substitute technologies available to prospective participants (that would also pass the TRC test). The burden of proof falls on the party sponsoring the analysis to show that the baseline comparison adheres to this requirement.

Our rules take a very cautious view of Load Building and Load Retention Programs, including programs that encompass "economic development" activities. Our rules reflect our concern that these programs may not serve the longer-term interest of ratepayers and are designed to ensure that ratepayer funding for these types of programs is authorized only if other (nonresource) benefits exceed the longer-term costs these programs may cause because they bring closer the need for new resources.

To this end, Rule 12 requires that proponents of load building or load retention programs (including economic development activities) carry the burden of proof to quantify the social or ratepayer benefits, and justify ratepayer funding for these programs. Rule 12 also requires that program proponents provide program-specific analysis to support any general conclusions about the net benefits of Load Building or Load Retention Programs, and such analysis must take into account any net effect on air emissions and increased load on the system. Finally, Rule 12 requires that load building and load retention programs be designed to avoid frustrating our goal of encouraging energy efficiency and energy conservation. These requirements, along with the source-Btu and environmental criteria in Rule 13, also apply to any fuel substitution program that has a predominately load building or load retention character.[44] The specific evaluation criteria for these types of programs set forth in D.93-11-017 provide guidance with which to review Edison' proposals in this proceeding.

44 As we discussed in D.92-02-075, fuel substitution programs can be designed to retain or build load, rather than to promote energy efficiency.

Our DSM rules apply to ratepayer-funded activities which produce energy efficiency, load management, fuel substitution, load retention, or load building impacts. Our rules provide guidance for determining the appropriate level of ratepayer funding for these types of activities, without regard to the type of accounting treatment they receive. For activities[45] which do not have such DSM impacts but serve other customer service purposes, we evaluate the funding requests based on need for ongoing funding and whether the activities relate to the provision of utility service. With these above guidelines in mind, we evaluate Edison's funding requests and supporting analysis. The following chart summarizes the funding we approve

45 These activities include, inter alia, requested O&M funding for Major Account Representatives and for Market Segmentation activities.

Chart 11-3

Adopted Customer Service and Informational and Sales Expenses
(1992 Million $)

	Balancing Account
I. Demand-Side Management	$65.8
A. Shared Savings Programs	$24.5
1. Residential Portfolio Total	$7.0
Retrofits	$5.2
Bidding	$1.8
New Construction	$0.0
2. Nonresidential Portfolio Total	$17.5
Retrofits	$11.0
Bidding	$3.5
New Construction	$3.0
B. Performance Adder Programs	$19.5
1. Residential Total	$7.7
Energy Managment Services	$1.7
Non-Mandatory Direct Assistance	$6.0
2. Nonresidential Total	$11.8
Energy Managment Services	$11.8
C. Non-Earnings Programs	$11.0
1. Residential Total	$2.8
Mandatory Direct Assistance	$1.2
Information	$1.6
Load Management	$0.0
Fuel Substitution	$0.0
Load Retention	$0.0
2. Nonresidential Total	$6.1
Information	$4.1
Load Management	$2.0
Fuel Substitution	$0.0
Load Retention	$0.0
3. Other DSM	$2.1
D. Measurement Forecasting and Reg	$10.6

	Balancing Acct.	O&M
II. CS&I and Sales O&M	$2.99	$9.65
A. Safety Services		$0.35
B. Economic Development	$2.99	$0.00
C. Energy Market Solutions		$3.90
1. Rate Design & Billing		$1.10
2. Market Research		$2.00
3. Market Segmentation		$0.80
D. Customer Technology Applications		$0.90
1. Bypass Coordination		$0.90
2. Customer Technologies		$0.00
3. Technology Commercialization		$0.00
E. Customer Energy Productivity		$4.50
1. Customer Analysis		$0.40
2. Major Customer Contact		$1.60
3. Field Representatives		$2.00
4. Outreach		$0.50
Total DSM, CS&I and Sales		$78.44

11.5 Summary of DSM Issues

Edison's original testimony placed priority on DSM activities that served as least-cost, environmentally sensitive alternatives to supply-side resources. As originally proposed, the programs would save 802 million kWh and result in a net reduction in peak demand of 346 MW in 1995. Edison's proposal was largely for a continuation of the 1992 general rate case cycle's mix of DSM programs, with some reclassifications. For its energy efficiency programs, Edison performed the required cost-effectiveness calculations. DRA originally recommended a DSM budget of $108.1 million. DRA agreed that Edison's programs pass the required tests for cost-effectiveness.[46] In fact, DRA supported the large majority of Edison's proposed DSM programs.[47] DRA's proposed reductions in the remaining programs were based largely on policy considerations.

The biggest differences between DRA's recommendations and Edison's for the test year concerned nonresidential programs, particularly Commercial, Industrial and Agricultural Energy Management Services, Nonresidential Information programs, Nonresidential Load Management, Fuel Substitution, Load Retention, New Technology Assessment, and Residential Information programs. In addition, DRA proposed a transition away from annual ratepayer funding to a perpetual pool of loan money to fund many of the DSM programs in the attrition years, particularly in the nonresidential sector.

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46 DRA, Logan, R.T. 27, p. 3179, lines 11-14.

47 DRA's testimony fully supported Edison's programs for Residential Energy Management Services; Residential and Nonresidential New Construction; Residential Appliance Efficiency Incentives; Mandatory Direct Assistance, Commercial, Industrial, and Agricultural Energy Management Incentives; DSM Bidding; Residential Load Management; all of the Measurement, Forecasting & Regulatory Reporting expenses (except New Technology Assessment), and Other DSM expenses.

In the settlement, Edison and DRA agreed to significantly different and reduced funding levels for DSM programs than either party recommended at the evidentiary hearings. In addition to reducing the balancing account funding for DSM to $47.2 million, the settlement shifts $12.8 million out of the balancing account to implement programs which the settlement now classifies as CS&I O&M costs. These programs are described in Exhibit 214 and are substantially similar to programs previously requested in Edison's original DSM balancing account request. The DSM funding level recommended in the settlement will result in lower energy and capacity savings, only 239.9 GWh and 50.9 MW (Ex. 214, p. III-1). No party other than the settling parties supported the settlement; in fact, parties took significant issue with most of the proposed settlement funding levels, especially the O&M request.[48]

<u>11.5.1. Conservation/Energy Efficiency Programs</u>

Edison originally proposed a budget of $103.8 million for Conservation and Energy Efficiency Programs. DRA recommended $80.9 million for the test year budget as well as modifications to the programs within this budget category. These adjustments are detailed below. The settlement recommends adoption of $34.7 million for Conservation/Energy Efficiency Programs.

<u>11.5.1.1. Retrofit Energy Efficiency Incentives</u>

Edison originally planned to implement three retrofit programs: Residential Appliance Efficiency Incentives (RAEI), Nonresidential Energy Efficiency Incentives (NEEI), and DSM Bidding. In their original testimony, Edison and DRA agreed on test year funding of $43.1 million for these programs. Under the settlement, Edison and DRA proposed total funding for these

48 Besides Edison and DRA, the following parties participated in the evidentiary hearings or briefing on Edison's original application with respect to DSM: CLECA, Cal/Neva, CEO, DGS, ICA, NRDC, SoCalGas, and TURN. Besides Edison and DRA, the following parties participated in the hearings or briefing on the settlement phase with respect to DSM: CEC, DGS, NRDC, SoCalGas, and TURN.

programs of $11.6 million. The settlement would eliminate funding for the Residential Program while retaining a reduced level of funding for Nonresidential and Bidding programs. The CEC proposed $29.2 million for Retrofit Energy Efficiency Incentives. NRDC proposed $43.1 million consistent with Edison's original request. Pursuant to our prior decisions, these programs receive shared savings shareholder earnings treatment.

The proposed RAEI program would offer (1) incentives to customers for the installation of energy efficient appliances, (2) manufacturer incentives for compact fluorescent bulbs (CFB) to reduce the retail price, and (3) a refrigerator recycling component. This program targets residential customers, regardless of their income level. Prior to the settlement Edison and DRA agreed on the funding for this program in the test year at $10.2 million, although DRA recommended the revenue requirement be reduced in the attrition years by converting the CFB component to a financing program.

Edison is currently running a Refrigerator Recycling Program in its service territory under a contract which was scheduled to terminate at the end of 1994 with an option to renew. This program made up $5.1 million of the requested RAEI funds, but Edison had no contractual obligation to pursue renewal of the contract. For the 1995 program year, Edison has shifted funds from its nonresidential portfolio to fund this program. (See Advice Letter 1078-E.)

For the CFB program, DRA (in its initial testimony) recommended converting Edison's manufacturer rebate into a self financing program. DRA recommended adopting the full funding level of $3.6 million for the test year, but eliminating the funding in the attrition years.

The efficient appliance measure would allow Edison to provide financial incentives to encourage residential customers to purchase high efficiency equipment. This program assists in moving the market toward higher production and purchases of energy efficient equipment.

The settlement recommended no funding for energy efficient incentives for residential customers. As stated above, for the 1995 program year, Edison has shifted funds from its nonresidential portfolio to serve its residential customers. The CEC recommended that Edison's programs for the residential sector focus on market transformation and reduction of market barriers, rather than traditional rebate programs, in the amount of $5.2 million.

In arriving at an authorized funding level for the RABI program, we seek to balance our desire to see a real reduction in Edison's revenue requirement with our desire to improve Edison's ability to achieve cost-effective energy savings. The settlement recommendation of no funding for Residential Retrofit Programs does not appropriately balance these interests, especially since Edison has shifted funds within its fund-shifting flexibility to serve residential customers during 1995. We will authorize $5.2 million for Edison's RABI program for each year of the rate case cycle.[49]

However, we will not identify the specific components of the programs which Edison should pursue. We will not specify the appropriate delivery mechanisms for the program components as DRA would for the CFB program. Because of the reduced funding level, we encourage Edison to actively explore alternate delivery mechanisms for its residential appliance programs. These alternatives may include, but are not limited to, leveraged loans, manufacturer rebates, and customized incentive levels. Edison should also take care that changes in delivery mechanisms do not result in abrupt termination that will hamper development of the energy efficiency infrastructure. Edison should work with its Advisory Committee in this effort. We note that pursuant to our decision in the shareholder incentive proceeding, Edison has the

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49 The allocation for this program should include the field labor component associated with the administration and delivery of the program. These costs were previously included in the Energy Management Services category.

ability to carry funds forward within a rate case cycle, providing it with additional flexibility in utilizing this funding level.

Edison's proposed NBEI program had three components: a Hardware Rebate Program, Efficient Motors and Compact Fluorescent Lamps (CFL). The Hardware Rebate Program offers rebates directly to customers for replacement of existing energy-using equipment. The Efficient Motors and CFL components provide manufacturer incentives. Edison initially requested $23.6 million for this program. DRA agreed with the test year request but would eliminate funding in the attrition years and encourage Edison to operate the NBEI program as a self-financing program. The settlement recommended $8.0 million funding for the NBEI program. The settlement did not specify how the funds will be used.[50] The CEC recommended $18.0 million. DGS and NRDC also urge the Commission to adopt a higher level than the settling parties.

We authorize $11.0 million for this program for each of the three years of the general rate case cycle.[51] The level we authorize is within the bounds of the original DRA and Edison positions over the general rate case cycle. (For the three-year general rate case cycle, Edison's proposal would require $70.8 million, while DRA's would have required $23.6 million.) In addition, this level recognizes that these programs only will be available to certain portions of Edison's service territory during the implementation of the DSM bidding pilots. Funding for the DSM bidding pilots is addressed next.

Like our decision in the RABI program, we will not specify the delivery mechanism for these programs. We encourage Edison to explore alternate delivery mechanisms with its Advisory

50 In fact, for the 1995 program year, Edison has shifted funds out of nonresidential programs into residential programs.

51 The allocation for this program should include the field labor component associated with the administration and delivery of the program. These costs were previously included in the Energy Management Services category.

Committee and to exercise its funding flexibility in order to achieve the most cost-effective energy savings. In addition, with the favorable Internal Revenue Service ruling related to DSM expenditures (Rev. Rul. 95-32), one of the primary impediments to Edison's pursuit of these savings (as indicated in Exhibit 214) has been removed.

The settlement recommended $3.6 million for DSM Bidding, allocating $1.6 million to the Residential pilot program and $1.9 million to the Nonresidential Small Offices pilot program but nothing to the Large Commercial and Industrial pilot program. The settlement relied on there being a six-year general rate case cycle to recover funds adequate to meet its obligations. We have reviewed Edison's funding request and will authorize $5.3 million annually. This is a reduction from the $9.3 million originally requested by Edison and not opposed by any party. Edison will participate in SoCalGas' Residential pilot program pursuant to D.92-09-080. We will grant Edison's original request of $1.8 million for the Residential pilot program.

We reduce the total authorized level because Edison had previously collected funds (in 1993 and 1994) for performance of the nonresidential pilots (see Advice Letter 1015-E-A). In addition, in D.94-09-041, we authorized Edison to reallocate funds between its Nonresidential pilots. This reallocation reduces the funding required for the small commercial pilot program from $2.1 million per year to $0.75 million per year for the seven year performance period. Edison needs to recover an additional $6.75 million to fulfill its Large Commercial and Industrial pilot program commitments. (See A.94-05-016 at pp. 5-6.)

In D.94-09-041, we also authorized Edison to carry over the unspent funds from the 1992 general rate case cycle which had been collected for these bidding programs which have not yet been expended. For these reasons we authorize $3.5 million annually for fulfillment of contractual obligations under the nonresidential bidding pilots. This funding level will collect all the funds required to fulfill all of Edison's commitments for these contracts, including those extending beyond the general rate case

cycle. Edison is authorized to carry over funds directed to DSM Bidding to meet commitments beyond the rate case cycle should they occur. Funding for both the residential and nonresidential DSM bidding levels is for three years only (i.e. from 1995-1997).

For all of the Retrofit Programs, Edison should not implement DSM measures that are not cost-effective at the end use level. As we require for all utilities, we require Edison (1) to update its cost effectiveness tests using adopted electric avoided costs and (2) to demonstrate that the measures it plans to pursue pass the TRC and UC tests consistent with our DSM rules. Edison should file this update as an Advice Letter within 60 days of the effective date of this decision. Funds for these programs will receive two-way balancing account treatment, consistent with our treatment of other utilities.

11.5.1.2 New Construction

Edison originally requested $11.3 million to fund New Construction Programs. DRA agreed with this request. Edison allocated this funding between Residential ($2.5 million) and Nonresidential ($8.8 million) programs. These programs are generally aimed at builders and architects to encourage them to construct homes and nonresidential buildings in a manner which exceeds Title 24 standards. Under D.94-10-059, New Construction programs are subject to shared savings treatment.

In the settlement, Edison and DRA recommended no funding for New Construction programs, but instead recommended that $500,000 be approved for Nonresidential New Construction Information programs. The CEC and NRDC both presented alternates to the zero funding level in their testimony at the settlement hearings. The CEC recommended $2.0 million for Residential New Construction and $6.2 million for Nonresidential New Construction. NRDC recommends $1.5 million for Residential New Construction and $8.8 million for Nonresidential New Construction. Both NRDC and CEC based their requests on the benefits of these programs for transforming the market, as well as the substantial opportunities for savings from the new construction market.

Economic conditions have negatively impacted program accomplishments in recent years. In fact, according to testimony in Edison's 1994 Annual Earnings Assessment Proceeding (AEAP), Edison's 1993 Residential New Construction program was not cost-effective on implementation. (See D.94-12-021, slip op., at p. 16, n. 8 and pp. 24, 26.)[52] Based on this information, we believe that the 1995 residential new construction rebate based programs originally proposed by Edison are unlikely to be cost-effective. If Edison wishes to maintain a presence in the building industry but its incentives are not cost-effective, we encourage Edison to do so through the provision of information to builders or buyers as part of its information and education programs. Therefore, we will not authorize any funds for Residential New Construction. However, new construction will remain part of the residential portfolio for purposes of shareholder earnings and fund-shifting.[53] If future conditions differ from today's, or Edison develops a new approach, Edison will have the flexibility to pursue cost-effective energy savings in the new construction arena.

Edison's Nonresidential New Construction programs have fared better than the Residential programs. We will authorize $3.0 million for this program. If Edison wishes to expand its Nonresidential New Construction Information program, as indicated in the settlement, it may do so within the authorized information budget. As we require for all utilities, we require Edison (1) to update its cost-effectiveness tests using adopted electric avoided costs and (2) to demonstrate that the program it plans to pursue passes the TRC and UC tests consistent with our DSM rules. Edison should file this update as an Advice Letter within 60 days of the

52 In Advice Letter 1075-E, submitted October 28, 1994, Edison notified the Commission that it had closed its 1994 residential new construction program because it was no longer cost-effective.

53 In other words, Residential New Construction should be a line item within that portfolio with zero dollars allocated.

effective date of this decision. Funds for these programs will receive two-way balancing account treatment, consistent with our treatment of other utilities.

11.5.1.3 Energy Management Services (EMS) Programs

Edison originally requested $22.6 million for EMS programs. DRA recommended a reduction of $10.4 million primarily from the Commercial and Industrial EMS programs. The settlement recommended $13.2 million. In their original testimony, DGS and CLECA indicated their support for lower levels of funding than Edison requested. In its original testimony, the CEC recommended implementing a fee-based audit structure. In its brief after the evidentiary hearings, Edison agreed to test this approach in a pilot program. In its testimony on the settlement, CEC recommended $13.2 million for EMS funding; NRDC recommended $20.3 million.

We adopt a funding level of $13.5 million for EMS programs, with $1.7 million for Residential programs and $11.8 million for Nonresidential programs, including Major Customer Contact. Edison's original request for Residential EMS activities was $3.9 million; no party opposed this request. In the settlement, Edison and DRA recommended this level be reduced to $1.7 million; NRDC and the CEC support this lower level. We will adopt this decreased level of funding for Residential EMS programs. We do not specify individual programs these funds should be allocated to, but encourage Edison to pursue the most effective program designs to serve residential customers.

Edison's original request for nonresidential EMS activities was $18.7 million; DRA recommended $8.1 million. DGS supported a lower level than proposed by Edison. The settlement recommended $11.5 million. The CEC supported the settlement level with certain conditions. NRDC recommended the Commission adopt the original Edison level. We adopt $11.8 million for nonresidential EMS activities including Major Customer Contact.

We address Major Customer Contact/Major Account Executives in the EMS category because the activities described in Edison's testimony better meet the definition of EMS activities than information activities since they are tailored to specific customer needs rather than generic conservation opportunities. Major Customer Contact is an activity that provides both energy efficiency and other services to customers. Edison has requested funds for this activity from DSM and from O&M costs. As such, we will allocate funding for this activity between the DSM balancing account and O&M expenses. Within the funds we have authorized for nonresidential EMS activities, we expect that Edison will continue to offer services and audits to all customer groups, investigate additional approaches to achieve energy efficiency in the nonresidential market, as well as provide Major Customer Contact services. We encourage Edison to pursue innovative approaches to reduce reliance on nonparticipant funding, like the fee for service approach recommended by the CEC.

We will adopt $1.6 million in O&M funds for Major Customer Contact/Major Account Executive activities, a level higher than Edison's original request and lower than the settlement level. We recognize that Edison's Major Account Executives will be providing services unrelated to DSM in addition to DSM services. Edison should only charge the DSM balancing account for costs incurred for Major Customer Contact/Major Account Executives associated with DSM activities. Funds for EMS programs will receive one-way balancing account treatment.

11.5.1.4 Information and Education Programs

Edison originally proposed $14.7 million in funding for Customer Information and Education Programs. In it's August 18, 1994 Opening Brief at pp. 33-34, Edison withdrew it's requests for three components of the program - Welcome Home Expense, Residential Program Oversight and Nonresidential Program Oversight, totalling $0.6 million - bringing its request to $14.1 million. Edison requested funding for some of these information program elements in both the DSM and non-DSM (O&M)

sections of its testimony. We will address the residential and nonresidential portions of the program separately. Edison's request also contains several program elements that serve both energy efficiency and other customer service goals.

Edison's total request in residential information was $2.5 million (after removing the withdrawn elements). These funds are requested for the Customer Technology Application Center (CTAC), Edison's Action Line, Residential Outreach and Rate Communication, two education programs, and water-energy partnerships. DRA recommended Edison's request for all of the program elements except the education and partnership programs be approved, a funding level of approximately $2.0 million. DRA reasoned that the education and partnership programs are ill defined and serve dual purposes which makes it difficult to measure the effectiveness of the energy conservation activities. Under the settlement, Edison and DRA recommended retaining only $0.4 million in residential information programs for CTAC. In its original testimony, CEC indicated its support for DRA's original position. In its testimony on the settlement, CEC recommended $1.5 million. NRDC's testimony on the settlement also recommended $1.5 million, a 40% reduction from Edison's original request.

As we have recommended above, we will not specify how many dollars may be spent on a particular program. However, we will provide guidance on what types of activities should be funded. We see some merit in DRA's position that Edison's education and partnership activities are ill defined. However, we believe these types of activities, if properly designed, provide a means of leveraging funds of many parties to deliver energy efficiency information. We will not prohibit Edison from entering into partnerships, but it should strive to enter into these arrangements using DSM funding only when they provide well-defined energy efficiency purposes. Only those costs associated with the provision of energy efficiency information should be charged to the DSM balancing account. CTAC and the Action Line clearly provide energy efficiency information to residential customers and are

appropriate information activities. We have also indicated in our discussion on New Construction that it might be appropriate to pursue involvement in this area by providing information.

With respect to the Residential Outreach program, its primary purpose appears to be the distribution of energy efficiency information. However, we recognize that Edison's outreach efforts may serve not only energy efficiency purposes but also such activities as analyzing bills and providing information on rate schedules. Therefore, funding should be split between DSM and O&M activities. We will approve $0.2 million in the O&M budget for residential outreach O&M activity, with the DSM activities being funded as part of the overall residential information funding level. We have also reviewed Edison's Residential Rate Communication program and have determined that it is a program whose main purpose is of a service nature rather than an energy efficiency purpose and therefore should not be included in the DSM balancing account. We authorize $0.255 million for this activity as part of the O&M budget, which is more consistent with the historical expenditure level. We believe this program may be more appropriately funded in a FERC account other than the CS&I accounts (for example, see the definition of Account 916). Edison should include a recommendation regarding which FERC account these funds should be assigned to in its Advice Letter filing which we describe in more detail above. In all, we authorize $1.6 million in DSM funds for Residential Information and Education Programs within the DSM balancing account and $0.455 million for Residential Outreach and Rate Communication activities as part of the O&M budget.

Edison's Nonresidential DSM Information request was $11.557 million (excluding withdrawn items). DRA recommended $5.5 million by eliminating funding for market segmentation, advertising and major customer contact. CEC indicated its general support of DRA's position. In the settlement, Edison and DRA recommended $6.9 million for nonresidential information programs, with a reduced level of funding for market segmentation, advertising, and major customer contact, and an additional $0.5 million for nonresidential

new construction information. In addition, funding for certain activities are now requested as part of the O&M request. CEC and NRDC supported the settlement levels for this request.

Nonresidential Information programs are defined as "programs intended to provide customers with information regarding generic (not customer specific) conservation opportunities." (Emphasis added; Reporting Requirements Manual, Fifth Edition, Appendix A, p. 3.) Only two of the program elements, nonresidential CTAC expenses and nonresidential outreach meet this definition. As we did for Residential Information programs above, we will adopt funding for Commercial, Industrial, and Agricultural (CIA) Outreach in both DSM and O&M budgets. We will approve $0.3 million in the O&M budget for non-DSM nonresidential outreach activities, with DSM activities funded as part of the overall Nonresidential Information funding level. We reach the same conclusion for Edison's nonresidential Rate Communication program as we did for its residential program. We will authorize $0.333 million in O&M funds for this activity which is more consistent with historical expenditure levels. Parties should review and recommend the appropriate FERC accounts to which to assign these costs.

Overall, we authorize $4.1 million for Nonresidential Information Programs and $0.633 million for nonresidential outreach and rate communication activities as part of the O&M budget. The approved funding incorporates the portions of Information Technologies Support and Energy Efficiency and Market Services Communications costs that are attributable to Edison's Information Programs. These funds may also be used for informational energy efficiency advertising; however, program specific advertising should be charged to specific programs.

The remaining requests are more appropriately addressed in other funding categories or assigned to specific programs. We addressed Major Customer Contact (Major Account Executives) in the EMS category. In addition, Market Segmentation clearly falls into the Measurement, Forecasting, and Regulatory Reporting (MFRR) category and will be addressed there. The workpapers describe Edison's advertising request as "program-specific" advertising. Program-specific advertising is considered a part of the cost of each program and should be incorporated into program funding rather than be part of the information category. Finally, Edison has requested funding for internal training as part of the information category. This activity does not meet the definition of an information program and we will consider it as part of the Other DSM category.

11.5.1.5 Direct Assistance Program (or Customer Assistance)

Edison originally requested a test year budget of $12.1 million for this program, with $2.2 million for weatherization services and $9.9 million for education and appliance replacement and maintenance. The Direct Assistance or Customer Assistance Program (DAP) offers low-income, elderly, and disabled customers energy services such as weatherization, building repair, energy education, and appliance repair and replacement. These services are currently provided through a network of community-based organizations (CBOs) and other third parties in conjunction with SoCalGas. DRA recommended $6.9 million, limited to mandatory efforts and cost-effective nonmandatory programs. Cal/Neva supported Edison's funding request and opposed DRA's recommendation to reduce DAP funding in light of the depressed economic climate in California and the more than one million homes in need of weatherization. DGS generally supported Edison's original request. The settlement recommended $2.6 million for this program. In their testimony at the settlement hearings, NRDC recommended adopting the full $12.1 million and the CEC recommended adopting $6.7 million.

Our DSM rules provide that DAP funding should not be based purely on cost-effectiveness. (See DSM Rule 11.) Rather, DAP funding levels should be based on a reasonable balance between the needs within the community and the costs to ratepayers. As stated in our DSM rules, direct assistance programs address equity concerns and, therefore, cost-effectiveness is not the sole factor used to determine funding levels for these programs. The record does not justify the settlement's severe funding reduction in this category.

In Advice Letter 1088-E, Edison requested the ability to carry over funds from the 1992 general rate case cycle to meet additional need for low-income services in 1995. That Advice Letter indicates the need to more closely examine the settlement in this area in particular. We are not satisfied that the settlement provides sufficient funds to meet the needs of this segment of the population. The amount of funding adopted in a general rate case should meet the need of the customers the program is designed to serve and not rely on speculative funds availability to bring it to an appropriate level. By relying on use of carryover funds to meet the true needs of its low-income customers, instead of providing sufficient funds in the settlement, Edison did a disservice to its low-income customers.

We adopt $7.2 million for this program, $1.2 million for mandatory measures, and $6.0 million for nonmandatory measures. We will adopt the settlement's recommendation for mandatory measures funding and we expect that the scope of services will remain the same as under the original request as described in Exhibit 214, p. I-14. We do not limit Edison's ability to utilize its nonmandatory funds on particular programs. Edison should work with low-income representatives to determine which types of programs best assist low-income customers in managing their energy bills when determining funding priority. For example, Cal/Neva suggested that Edison should develop a more effective system for identifying

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eligible units for weatherization services and work cooperatively with its program contractors to locate eligible households. Cal/Neva suggests that Edison's Weatherization Advisory Group would be an appropriate forum to explore creative methods to improve and expand Edison's outreach efforts. This may be an effective method of outreach for CARE programs as well.

By adopting $7.2 million, low-income customers will receive necessary assistance in managing their energy bills over the rate case cycle, without relying on carryover funds or fund shifting. As such, Edison should return the carryover funding which was previously authorized in Resolution E-3414 to ratepayers. Edison should file a report within 60 days of the effective date of this decision setting forth how it has returned the carryover funding to the ratepayers. These funds are subject to one-way balancing account treatment.

11.5.2. Load Management

Edison originally requested a total of $7.3 million for residential and nonresidential load management activities. DRA agreed with Edison's $1.1 million request for residential load management activities, but recommended only $3.0 million for nonresidential activities. DGS generally supported Edison's original request. In the settlement, Edison and DRA recommended no funding for residential activities and $1.3 million to honor existing Energy Cooperatives commitments. Edison indicated in Exhibit 214 that expenditures for rate-related load management programs such as air conditioning cycling and interruptibles (representing $3.8 million of Edison's original request) will be funded outside of the DSM balancing account because the value of these programs extend beyond just their resource value. In its original testimony (Exhibit 37/37A), Edison indicated that most of these activities are no longer marketed but the programs continue to accept interested customers. In its testimony on the settlement, NRDC recommended $3.5 million to fund nonresidential

load management activities; CEC recommended $4.3 million for nonresidential activities.

The DSM Test Project is an existing commitment that has been fully funded in Resolution E-3414 utilizing carryover funds. No additional funds are necessary for this project. Several of the other programs are not actively marketed but continue to sign up customers. We believe it is appropriate to provide some funding to meet ongoing commitments and accommodate new enrollment. Although Edison indicates that these programs have value to customers that extends beyond resource value, they still represent a dispatchable load available to Edison to meet system demand. Since all parties supported the reduction in residential load management funding and the program is no longer marketed, we will eliminate funding for residential load management activities. We adopt $2.0 million for nonresidential load management activities to fulfill contractual commitments not already funded through carryover funds or to engage in other load management activities consistent with our DSM rules. These funds are subject to one-way balancing account treatment.

11.5.3. Fuel Substitution

Edison originally requested $1.5 million for Fuel Substitution programs, which are defined as programs intended to substitute energy-using equipment of one utility-supplied energy source with a competing utility-supplied energy source. Edison's proposed activities included Commercialization Projects and a Technologies Program. As described in Section 11.4 above, Fuel Substitution Programs must pass a three-prong test to be considered for ratepayer funding:

a. The program must not increase source-Btu consumption.

b. The program must have a TRC and UC test ratio of 1.0 or greater.

c. The program must not adversely impact the environment.

d. For purposes of applying these tests, the most efficient same-fuel technology that would pass the TRC and UC tests is to be used to compare technologies offered under fuel substitution programs.

In its original testimony, DRA recommended no funding because Edison did not demonstrate that its proposed programs comply with the Commission's rules for fuel substitution. DGS supported DRA's recommendation. In the settlement, Edison and DRA eliminated fuel substitution funding from the DSM balancing account. However, under the settlement, programs with the same description are funded under the O&M budget at an increased level. NRDC and CEC both recommended no ratepayer funding of fuel substitution activities in their testimony on the settlement. In addition, the CEC recommended no funding for these activities in the O&M budget if one-way balancing account treatment does not apply.

We stated in D.92-10-020:

> "Rule 13 makes it clear that we discourage utilities from pursuing fuel substitution programs with a predominantly load building or load retention character. In addition to demonstrating that these programs pass the environmental and source-fuel tests described below, utilities carry the burden of proof to demonstrate that the benefits of the programs justify relaxing our focus on energy efficiency programs (i.e., relaxing the Total Resource Cost test of cost-effectiveness requirement)." (D.92-10-020, 45 CPUC2d 683, 686-687)[54]

54 This discussion was in response to SoCalGas' request to modify the definitions of load retention and load building to explicitly exclude Fuel Substitution programs.

We reiterated this statement in D.93-11-017, which considered DSM rules for Load Building, Load Retention, and Economic Development programs. (D.93-11-017, slip op. at p. 15.)

Edison's direct showing for these programs did not meet the burden of proof required for us to authorize ratepayer funding for these activities, since Edison did not demonstrate that its programs meet our three-prong test. Edison stated in its rebuttal testimony (Exhibit 207A at p. 15) that two technologies it presented in its testimony do not pass the three-prong test. Edison did not present a three-prong test analysis for the remainder of its fuel substitution program. Under the settlement, the Customer Technologies and Technology Commercialization programs have descriptions which differ very little from the previously proposed fuel substitution programs. Again, Edison did not demonstrate how these activities meet our three-prong test.

While Edison intends to pursue fuel substitution, load retention and other activities with DSM impacts, Edison proposes that the funds transferred to O&M not be subject to the Commission's DSM rules because the program names are changed and the programs are booked to an O&M instead of a DSM account. SoCalGas supports Edison's request to be exempt from the Commission rules, if all utilities are afforded comparable treatment so that there is no competitive advantage for one utility.

The generic DSM Rulemaking/Investigation addresses DSM activities of all types without limiting its applicability to specific accounting treatment. Any DSM activities undertaken by a utility are subject to the funding and implementation DSM rules. (DSM covers, inter alia, energy efficiency, load building, load retention, fuel substitution activities described in the DSM rules.) Simply changing the name of a program and requesting different accounting treatment, or stating that the program is necessary to meet customer-specific needs, does not change Edison's

requirement to meet its burden of proof to receive ratepayer funding for programs and activities which have DSM impacts. TURN and other intervenors have argued that the settlement's shift of funds for programs which promote fuel substitution, load building and load retention efforts into O&M accounts without requiring them to meet applicable DSM rules is inconsistent with past Commission decisions and current Commission guidance. As TURN indicated in its brief on the settlement, "[w]hatever one thinks of the applicable DSM rules and protocols, their underlying goal is as vital today as it ever was: ratepayers should not be required to fund activities which do not serve their broad interest. A change in nomenclature should not be allowed to undermine this important regulatory goal." (Pp. 23-24.) We find the arguments of TURN and other intervenors to be persuasive on this issue.

Our DSM rules serve as guidelines for what activities are appropriately funded by ratepayers for all utilities. As DSM Rule 4 states, "To ensure optimal funding of DSM activities requires consistent treatment of programs across utilities and across regulatory forums." If Edison wishes to pursue a change to our DSM rules, the DSM Rulemaking/Investigation is the proper forum. If Edison wishes to pursue fuel substitution activities that are not consistent with our DSM rules, it is free to do so using shareholder funding.

11.5.4 Load Retention and Load Building

In its original request, Edison sought $2.2 million for load retention activities and no funding for load building. DRA recommended $1.1 million. The originally proposed programs included a Technologies program and a Commercialization program with the same goals as the Fuel Substitution programs of the same names. DRA recommended not funding these activities because they did not pass the applicable Commission rules. DRA recommended full funding for bypass deferral activities (also called bypass

coordination). DGS agreed with DRA's position. Under the settlement, Edison and DRA agreed to fully fund bypass deferral activities ($0.9 million) using O&M funds. The CEC and NRDC both recommended no ratepayer funding for these activities.

Because the bypass deferral activities are consistent with applicable Commission rules, we will authorize $0.9 million in O&M funds for this activity. As discussed above in the Fuel Substitution area, we will not authorize additional funds for commercialization or technologies activities because Edison did not meet its burden of proof to demonstrate compliance with Commission rules. Edison did not identify the rate and resource planning effects of these efforts, or provide a program-specific analysis, as Rule 12 requires.

11.5.5. Measurement, Forecasting and Regulatory Reporting (MFRR)

The utilities measure and evaluate the results of DSM programs in order to calculate the savings generated from those programs. The post-installation (ex post) measurement of programs savings through load impact and persistence studies links the results of DSM programs to utility shareholder earnings. Utility MFRR budgets fund these measurement activities as well as other demand-side measurement activities which are not directly related to program savings measurement. These other activities include customer surveys, new technology assessment, and load metering.

Edison originally requested an MFRR budget of $19.3 million, which is greater than its 1992 authorized expenditures. Edison explained that its budget reflects an increase in ex post measurement activities as well as its reliance on energy efficiency to meet its resource needs. Edison's budget included $5.2 million in funds for New Technology Assessment. These funds would be used for MFRR activities associated with the fuel substitution activities discussed above. Edison stated that this portion of the MFRR funding would allow Edison to identify technologies that

provide energy efficient solutions to customers' energy needs. DRA originally objected to $2.9 million of the New Technology Assessment activities that did not relate to in-situ technology testing, consistent with its opposition to the "Fuel Substitution" program.

In the settlement, Edison and DRA agreed to an MFRR funding level of $9.3 million. The settlement does not utilize our adopted MFRR categories for purposes of classifying funding for MFRR activities. The CEC recommended $11.4 million to correspond to its recommended total DSM budget of $83 million. NRDC recommended $17.2 million to correspond to its recommended $122 million budget. Because we adopt an overall funding level for DSM activities which is similar to that recommended by the settlement, we will adopt a comparable level of MFRR funding. Consistent with DRA's original recommendation and our above discussion on fuel substitution and load retention activities, we will reduce new technology assessment funding to $2.3 million.[55] As we discussed in the information category above, market segmentation is part of the MFRR category. Edison may pursue market assessment research to assist in its DSM program design within the authorized funding level.[56] We will increase the funding for the program evaluation area by $1.5 million to correspond to our higher level of funding for shared savings activities. Accordingly, we adopt an MFRR level of $10.8 million. This funding will receive one-way balancing account treatment.

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55 It appears that New Technology assessment activities may be most properly accounted for in FERC account 912.

56 We address additional market research and market segmentation funding requested as part of the O&M budget below.

11.5.6 Other DSM

This category is reserved for the costs of managing DSM programs. In its original testimony, Edison requested $4.7 million for its "Other DSM" category. DRA agreed with Edison's request. In the settlement, Edison and DRA recommend $1.9 million. NRDC recommended $3.7 million; CEC recommended $2.1 million. With the general reduction in the DSM program budget, lower costs should be incurred to manage the DSM programs. We will adopt the CEC recommendation of $2.1 million. This funding should also cover any internal training previously requested in the information area.

11.6 CS&I O&M Funding Request

In its initial testimony, Edison requested $11.1 million outside of the DSM balancing account as part of its O&M budget for activities it classified as non-DSM O&M activities. This request included funding for Major Customer Contact, Market Segmentation, Market Research, Customer Analysis, Safety Advertising, and Economic Development. DRA originally opposed all of this request except for Edison's Safety Advertising program. In the settlement, Edison and DRA agreed to the full $11.1 million and augmented the O&M funding request by $12.8 million. The additional $12.8 million is divided into three general categories,[56] some of which duplicate funds previously requested in the original request: Energy Market Solutions, which includes Rate Design and Billing; Customer Technology Applications, which includes Bypass Coordination, Customer Technologies, and Technology Commercialization Services; and Customer Energy Productivity, which includes Major Account Executives,[57] Field Representatives, Outreach, and Customer Analysis. The CEC recommended lower levels of funding than

57 Major Account Executives and Major Customer Contact appear to be different names for the same activity.

requested for the O&M area and recommended no funding if the funds are not subject to balancing account treatment. We will address these requests, which were presented separately, as one request. The following table represents the settlement request for CS&I O&M funds.

Table 11-4
CS&I O&M Settlement Funding Request
(1992 $ millions)

Safety Services	0.4
Economic Development	5.8
Energy Market Solutions	
Rate Design & Billing	2.6
Market Research	2.9
Market Segmentation	0.8
Subtotal	6.3
Customer Technology Applications	
Bypass Coordination	0.9
Customer Technologies	1.7
Technology Commercialization Services	0.6
Subtotal	3.2
Customer Energy Productivity	
Major Account Executives	2.2
Field Representatives	4.4
Outreach	0.7
Customer Analysis	0.9
Subtotal	8.2
Total	23.9

11.6.1 Safety Services

Edison originally requested $0.35 million for safety services, specifically kite safety activity. DRA disputed $0.04 million of the request on the basis that only a portion of an educational booklet related to safety. Under the settlement, Edison and DRA agreed to Edison's original funding level. No other party took issue with Edison's original request or called out the safety issue in testimony on the settlement. We will adopt Edison's original funding level for this activity.

11.6.2 Energy Market Solutions

We previously addressed our intent to provide funding for certain rate related communications activities, requested under the DSM Information category, in the O&M budget. In the settlement, Edison and DRA agreed to additional funding for expanded activities in this area which they designate as Rate Design and Billing. Edison did not justify its $2.6 million request. However, we believe this activity provides some ratepayer benefit and therefore authorize $1.1 million for this activity which includes the previously adopted $0.59 million discussed in Section 11.5.4.

Based on the description of Energy Market Solutions in Exhibit 214 (see p. II-5), Edison's requested market segmentation and market research funding seem to fall under this general program description. It is clear based on Edison's original testimony that additional research and segmentation activities are underway by the utility --- some relate to the provision of DSM services, others do not. Accordingly, under the same rationale as set forth in the previous paragraph, we will authorize $2.0 million for market research and $0.8 million for market segmentation activities as part of the O&M budget. Costs for activities that are consistent with our DSM rules may be booked to the DSM balancing account within the authorized MFRR funding levels; market research and segmentation activities of a non-DSM nature should be charged to O&M. These funds will not receive balancing account treatment.

11.6.3 Customer Technology Applications

As we discussed above in the fuel substitution and load retention sections, we will authorize funding for the requested bypass coordination activities in the amount of $0.9 million. This program meets the applicable DSM guidelines for ratepayer funding. We do not authorize funds for Customer Technologies or Technology Commercialization activities because Edison has not met its burden of proof for ratepayer funding of those activities.

11.6.4 Customer Energy Productivity

We previously indicated our approval of $0.5 million in O&M funding for outreach activities. In the settlement, Edison indicated that it and DRA propose that outreach costs, both DSM and non-DSM in nature, be allocated to O&M. We adopt a level of funding which is lower than proposed in the settlement in part because we believe that some costs associated with outreach are appropriately allocated to DSM information programs. Edison should work with DRA to develop an appropriate allocation mechanism between DSM and O&M costs for outreach activities.

With respect to Major Account Executives (or Major Customer Contact), Edison originally requested a total of $2.4 million allocated between DSM ($1.7 million) and O&M ($0.7 million) accounts. In the settlement, Edison and DRA proposed an additional $1.5 million in O&M funds for this activity. As part of Edison's EMS programs, we authorized funds associated with Major Account Executives for their work related to DSM programs. Here we authorize funding for their activities unrelated to DSM based upon the same rationale. We authorize $1.6 million for Major Account Executives as part of the O&M budget. This funding is not subject to one-way balancing account treatment.

As part of the settlement, Edison and DRA agreed to an additional $4.4 million for field representatives. The description of the activities for these field representatives indicates that their time will primarily be spent on DSM activities but that customers are increasingly expecting broader assistance from their field representatives. Costs for field representatives associated with DSM activities are already authorized as part of the DSM program budgets. The settlement testimony does not provide any justification as to the allocation of time between DSM and O&M activities nor does it provide justification for how it arrived at the level of staffing to be funded using O&M funds. We agree that some percentage of field representatives' time will be spent on

non-DSM activities, but we have not received enough information to justify the $4.4 million level recommended by the settlement. We will authorize $2.0 million in O&M funding for this activity. Edison should only allocate field representatives' time spent on DSM activity to the DSM balancing account; all other time should be funded from O&M.

Edison requested $0.6 million for Customer Analysis as part of its original O&M request. The settlement indicated that Edison and DRA have agreed to an additional $0.4 million, but cut back the original request to $0.5 million, bringing the total request for Customer Analysis to $0.9 million. This particular request points out the difficulty with Edison's presentation of its case by artificially separating its O&M request into two parts. In Table II-1 of Exhibit 214, it appears that the settling parties relied on the fact that Edison had previously requested $0.6 million for this activity to arrive at a settlement of an additional $0.4 million when they had also previously settled on $0.5 million based on the same original request. (Essentially, the settling parties agreed on a $0.9 million level based on Edison's original testimony of $0.6 million.) We will authorize $0.4 million in O&M funding for this activity.

12. Economic Development, Governmental Affairs and Educational Services

12.1 Economic Development

12.1.1 Summary of Request

In its original testimony, Edison requested $5.8 million for test year 1995 for its economic development program. Edison divided its program into short-term and long-term strategies and identified over 14 specific program components to meet its 1995 business retention goals. Julie Meier Wright, Secretary of the California Trade and Commerce Agency, presented testimony supporting Edison's economic development request, stating that it complements her agency's efforts.

DRA's primary recommendation at evidentiary hearings was that the Commission reject most of Edison's request and authorize Edison a budget of $25,000 for training in economic development issues. DRA's alternative recommendation in the event the Commission wished to grant Edison an advertising budget for economic development was that the budget should not exceed $300,000, which was the amount granted to SoCalGas in its last general rate case, D.93-12-043. In the introduction to its opening brief, DRA also alternatively argued that if the Commission grants a larger portion of Edison's request than that recommended above by DRA, it limit that amount to historical expenditures associated with Edison's customer-specific projects.

The settling parties, although not in agreement regarding the standard for establishing ratepayer benefits resulting from economic development programs, agreed to Edison's funding request in order to obtain the overall ratepayer benefits of the settlement. The settling parties also agreed that the program should be funded at the same level in 1996 and 1997, and Edison agreed not to seek increases during these years above the level provided by the then-applicable escalation provisions. The settling parties also agreed that the program's funding during the three-year rate case cycle be subject to one-way balancing account treatment, subject to true-up at the end of 1997. Edison also

agreed to track the time employees not assigned to its economic development program spend performing customer bill analyses and DSM-related analysis in direct support of Edison's economic development program activities and to charge that time to the economic development program.

12.1.2 Commission Rules Regarding Funding Economic Development Programs

Before discussing Edison's funding request in more detail, it is useful to understand the criteria we use to determine if ratepayer monies should fund economic development programs.

PU Code § 740.4 provides in pertinent part that "[r]easonable expenses for economic development programs ... shall be allowed, to the extent of ratepayer benefit."

In D.93-11-017, we clarified the Commission's policies and funding criteria for DSM programs that retain or build load on the utility system, including programs designed to stimulate economic development. We stated that it is the Commission's responsibility to ensure that the level and kind of ratepayer funded DSM activities serve the ratepayers' long-term interests, and "that our DSM Rules establish that the longer-term interests of ratepayers are best achieved by focusing DSM activities on programs that serve as reliable, least-cost, environmentally sensitive alternatives to supply-side resource options." (D.93-11-017, slip op. at p. 7.)

We emphasized that our DSM Rules take a very cautious view of load building and load retention programs, including "economic development" activities, e.g., technical assistance or incentives, designed to retain businesses that would otherwise leave a utility service territory or California. (See D.92-02-075, 43 CPUC2d 316, 330.) We developed the DSM Rules to "reflect our concern that load building and load retention programs (including economic development activities) may not serve the longer-term

interest of ratepayers, an interest that is our responsibility to protect. Our Rules are designed to ensure that ratepayer funding for these types of programs is authorized only if other (nonresource) benefits exceed the longer-term costs these programs may cause by bringing closer the need for new resources. (D.93-11-017, slip op. at p. 10.)[58]

The DSM Rules adopted in D.93-11-017, Attachment 1, provide a multipart test which a proponent must meet in order to receive ratepayer funding for economic development programs.[59] First, a project proponent should demonstrate that its proposal passes the Ratepayer Impact Measure (RIM) test both with and without the incorporation of nonprice factors set forth in Rule 7. (See Rule 12b.) The RIM test considers the impact of projects on utility sales and associated revenues. Since load building and business retention activities are designed to increase loads relative to what would occur without those activities, they can potentially lower rates by spreading utility revenue requirements across a greater number of customers and greater sales volume. Our DSM rules establish that the proponent of such projects should quantify this impact as a condition for funding.

However, a positive RIM test result is not a sufficient demonstration of ratepayer benefits. As we have explained in previous Commission decisions, the RIM test does not provide a complete picture of the longer-term total resource acquisition costs associated with DSM, including load building and load

58 We found that these Rules are consistent with the statutory requirement that programs to promote economic development be allowed in rates to the extent of ratepayer benefit. (See PU Code § 740.4.) (Id.)

59 We have recently updated the DSM rules in D.95-06-016, Attachment 1, Appendix 3.

retention activities. (See D.92-02-075, 43 CPUC2d at 330, 334.) The total resource acquisition costs required to support the increased or retained load over the longer term may offset the benefits of spreading utility revenue requirements over a larger sales volume. For this reason, our rules require that proponents of economic development programs also demonstrate that ratepayer benefits outweigh the short- and long-term resource acquisition costs associated with the proposed program. (See Rule 12.)[60] Prior to June 1995, our rules also required that the application of cost-effectiveness tests and program-specific analysis be conducted at the individual measure, program component and element level. In D.95-06-016, we modified our Rules to require disaggregation at the end use level.

A proponent must also demonstrate that its proposal is designed to complement to other federal, state, and local efforts, and does not unnecessarily duplicate other agencies' efforts. Finally, the proponent must demonstrate that the proposed program advances one or more of the utility's traditional responsibilities to provide safe, reliable, nondiscriminatory and reasonably priced energy services within the utility's own service territory. Our rules state that ratepayers should not fund load retention or load building programs that are primarily intended to actively solicit existing customers of other California utilities which have expressed no intent to relocate. With these criteria in mind, we now discuss the specifics of Edison's proposal.

60 Pursuant to Rule 12, the proponent must also (1) identify the effect on core customers of programs that increase load in noncore markets; (2) identify expected program benefits in terms of rate effects, resource planning effects, and other effects; and (3) identify net program impacts by isolating the benefits that can be attributed to the program from those that might occur even in the absence of the program.

12.1.3. The Program

12.1.3.1. Short-Term Strategy

Edison divided its proposed program into two broad categories: short-term strategy and long-term strategy. Its short-term economic development strategy consists of activities that encourage existing industrial customers to retain or expand their facilities within the service area and that provide prospective customers outside the service area with information to evaluate the merits of locating facilities within the region. Edison's funding request for its short-term strategy is about $2.9 million. Edison's broke down its short-term strategy into two "broad categories": Project Coordination, and Information and Analysis Services. (See Exhibit 26, p. 10.)

Project Coordination consists of time spent by economic development program teams working with and providing information to individual customers. The budget allocated for this category also consists of communications expenses, primarily for media advertising, trade show exhibits, and workshops on economic development. As stated above, in its original testimony, DRA recommended that the funding level for this category be $25,000, which Edison has budgeted for training of Edison personnel regarding economic development issues.

Edison broke down the Information and Analysis Service of Edison's short-term program into six components: (1) a Market and Demographic Studies component to provide customers with public-domain market and demonstration data already compiled for utility planning or regulatory purposes, as well as customized market and demographic studies for specific customer siting purposes; (2) a Site Selection component to provide what Edison states would be objective information about candidate site locations, even though customers generally use their own real estate brokers to find specific properties for relocation; (3) a New Customer Welcome component to provide new industrial customers with information

regarding resources available from Edison, government agencies, colleges and universities, and other sources; (4) a Technology Transfer component to familiarize customers with the University of California at Irvine's database and software targeted to high technology companies. Edison also proposed to assume the marketing functions of El Camino College's California Manufacturing Technology Center, which is geared to assist small and mid-sized industrial companies with training in Total Quality Management and Computer Integrated Manufacturing; (5) an Export Assistance component to assist customers in becoming more knowledgeable about export potential and the international trade process; and (6) a Measurement and Evaluation component.

12.1.3.2 Long-Term Strategy

Edison requested $2,835,992 for its long-term strategy. Edison divides this program into two broad categories: Industry Development and Business Climate Enhancement.

Edison stated that Industry Development is designed to strengthen the region's industrial base by helping existing and emerging industries overcome some of the difficulties stemming from competitive pressures in other states, Mexico, and overseas. Edison's program is divided into four separate components: (1) a Cluster Studies component to conduct studies on regional industry clusters. These studies are to show how certain industries can maintain competitiveness by recognizing the geographic linkage between industries, their suppliers and customers; (2) a Public-Private Partnership component of which CALSTART is an example.[61] DRA stated that in response to a data request, Edison explained that the balance of the budget for this item to be used for four

61 CALSTART is a partnership of over 40 public and private organizations designed to help create an advanced transportation industry.

other partnerships including an alliance of motion picture and television producers and government and an environmental technology-industry partnership, although it was impossible to predict with certainty which industries would be most promising in 1995; (3) a Business Incubators component, where Edison would identify prospective incubator projects for which its involvement can help facilitate the success of local small businesses; and (4) a Regional Recovery component to fund continued regional recovery in areas affected by civil unrest, such as the Los Angeles riots, as well as urban blight. Activities might include helping to recruit industries and establish small businesses in the area.

Edison proposed a Business Climate Enhancement program, which involves working with a variety of public and private initiatives to remove some of the obstacles that cause a majority of industrial customers to rank Southern California as a poor place to do business. The program has four components: (1) a Team Cities component which is to bring together business leaders and local government officials to focus on strategies that will strengthen the local economy because government-driven efforts to foster regional economic cooperation have not been successful; (2) a Business As Customer component which uses Edison's skills in providing customer service to help local cities and agencies adopt a customer-focused approach to their dealings with the business community; (3) a Regional Report Card component, a survey of businesses throughout its service territory regarding the performance of institutional and infrastructure suppliers, i.e., cities, utilities, transit authorities, government and regulatory agencies, etc.; and (4) and Issues Forums component which would hold meetings and workshops that help local business leaders and government officials examine a variety of concerns to the business community. Additionally, Edison planed to research and communicate the benefits of its long-term economic development proposals.

12.1.4 Discussion

We agree with DRA that since the legislature has enacted PU Code § 740.4, the issue presented for review is not whether economic development programs are good. The issue is whether Edison has met its burden of proof in showing that its program demonstrates ratepayer benefits.

D.93-11-017 requires among other things that load building programs, which include economic development programs, meet both a ratepayer impact measure (RIM II Test, Rule 12b) and a test which compares ratepayer benefits and long term resource acquisition costs (Rule 12) (D.93-11-017, Figure 1). These programs among other things must also "relate to the utility's traditional responsibilites to provide safe, reliable, non discriminatory and reasonably priced energy service within the utility's own service territory." (D.93-11-017, mimeo, Attachment 1, p. 9.)

In our discussion of the service establishment charge in Section 10.2.2 above, we recognized the role played by economic conditions of Southern California in influencing our policy decision. We also recognize these conditions at this time in our assessment of Edison's justification of its economic development program.

Edison has presented RIM test results which suggest that the economic development program meets this test. These test results contain two prominent subjective elements, the risk factor of the customer relocating outside the service area and the role which Edison played in retaining the customer. The subjective nature of these elements affects the strength of Edison's analysis and the extent of our funding of economic development.

In a discussion of its long term strategic activities in economic development, Edison presented an analysis of the discounted net contribution of fixed costs per kwh, which shows values of 0.037, 0.031 and 0.027 dollars for the years from 1998 through 2000 (Exhibit 26, Appendix, Table C-14). Although Edison describes this as a long term analysis, Edison does not clearly

relate this net contribution value to the required test which compares ratepayer benefits to long term resource acquisition costs. Nor does Edison present comprehensive support for the other D.93-11-017 criteria. This lack of clarity affects the strength of Edison's analysis and the extent of our funding authorization.

We will not approve Edison's request for $5.8 million for economic development because its request relies on factors which are substantially subjective and because Edison has not clearly and comprehensively presented its analysis to fulfill D.93-11-017 criteria. However, we will allow Edison to continue its economic development program at the level which Edison reported it would incur in 1994 of $2.989 dollars (Exhibit 26, Appendix A, page A-1). We note that Edison can use shareholder funding to support the other $2.9 million of its request for 1996 and 1997 and that we will allow Edison to present an Application for ratepayer funding for these programs which comprehensively meets the test requirements included in D.93-11-017. The request in Edison's application, should it choose to file it, should be limited to the difference between its economic development request in this rate case and the amount we have authorized for economic development in this case.

We also adopt the following provisions for the economic development program which Edison agreed to in the settlement. The funding which we authorize for economic development for the rate case cycle (1995-1997) should be subject to one-way balancing account treatment, subject to true-up at the end of 1997. Edison should track the time employees, not assigned to Edison's economic development program, spend performing customer bill analyses and DSM-related analysis at the request of and in direct support of Edison's economic development program activities and charge that time to the economic development program.

Also, we put all applicants on notice that we will require a utility to comprehensively meet the requirements of D.93-11-017 in future Applications.

12.2 Local and Regional Governmental Affairs

Edison originally requested $2.76 million for test year funding of local and regional governmental affairs activities. This requests consists of $1.063 million for local and $1.693 million for regional governmental affairs. At evidentiary hearings, DRA recommended a $1.492 million decrease for both categories, or a $392,000 decrease for local and a $1.1 million decrease for regional governmental affairs.

The settling parties stated that because these expenditures are necessary to provide adequate service to local and regional governmental entities and minimize costs to other ratepayers, and not for enhancement of corporate good will, DRA agrees with Edison's position.

12.2.1 Local Governmental Affairs

Edison described that the local governmental affairs organization's major activities include research and analyses of the local ordinances of 176 cities and 14 counties. This organization minimizes costs for its customers by, among other things, (1) providing information on local government compliance issues to other Edison personnel, (2) helping to ensure that Edison pays only what is required by local government taxes and fees, (3) providing information in response to issues that local government agencies, community organizations, and individual customers or groups have in connection with Edison's activities such as undergrounding projects, acquiring rights-of-way, etc., and (4) working with local community organizations on the environmental aspects of the siting of electrical facilities.

DRA questioned why Edison has experienced an increase of almost 100% in real dollars in the last ten years on local government affairs. DRA traced this increase to the budget increase for 1988/1989, which DRA believed was due to staffing changes because of an increase in the threat of municipalization. In DRA's opinion, the threat of increased municipalization is exaggerated. The overall impacts of a potential municipalization

on resource planning issues should not automatically be viewed as negative, and could vary greatly depending upon the location and load characteristics of the customers within the municipality. Therefore, DRA recommended a $392,000 reduction.

Edison stated that the 1988/89 budget increase was due to the transfer for four existing personnel to local governmental affairs throughout calendar year 1988, and the establishment of a new managerial position, and that the transfer of four existing personnel represented a shift of expenditures from one budget to another and did not create new positions. Edison added that three of the transferred positions continue to be responsible for administering and supporting Edison's provision of streetlight service. Because Edison stated that the increase costs for this account represent a shift, not an increase, of expenditures, we approve Edison's request.

12.2.2 Regional Governmental Affairs

In its original testimony, Edison stated that the regional governmental affairs organization is the field organization which interacts daily with local government and community officials on various issues such as cities, counties, special taxing districts, transportation agencies, regional planning agencies, etc. Edison explained that this request is 25% above the 1992 recorded level due to company reorganization, which supported an increase focus on governmental entities. Local government entities have been facing severe revenue shortfalls and are therefore considering actions to increase business license taxes, utility user taxes, and other revenue-producing mechanisms. In the 1992 to 1993 time frame, Edison stated it saved customers a little less than $100,000 in the negotiation of reduced business license taxes, obtained a $200,000 savings associated with expediting a construction permit, and pursued a property tax settlement before the Commission in I.92-03-052.

DRA recommended Edison's request be reduced by $1.1 million. DRA stated that Edison's budget has increased almost 200% since 1991, from $693,000 to $1.693 million, and that Edison has not justified this increase. The less than $100,000 in reduction of business taxes does not cost-effectively justify the expansion Edison requests in its budget. DRA also stated that the construction permit issue appeared to be a nonroutine matter and the third, the property tax settlement, has now concluded. Edison's justification for the budget increase because the reorganization placed more importance of Edison's role in the community is inadequate because such activities serve both Edison's image enhancement and goodwill.

Edison responded that the activities of its regional governmental affairs employees are not lobbying as described in FERC's description of Account 426.4, which differentiates which expenditures for civic, political, and related activities should and should not be charged to ratepayers as operating expenses. Edison described in more detail the activities of the employees such as providing information packages on tax issues, undergrounding electric facilities, resolution of construction issues, and obtaining land use permits. Edison's request contained an $11,000 reduction for lobbying activities.

We agree with DRA that Edison has not met its burden of proof in justifying such a significant increase in its requested budget for this account. Moreover, as set forth in Section 13.13 below, we have a broader interpretation of lobbying activities with respect to FERC Account 426.4 than does Edison. Edison has not convincingly established that all of the activities delineated for this account except for $11,000 worth of activities fall within Account 426.4's exception. However, based on Edison's testimony, we believe that there have been some increased expenses in this account which it would not be equitable to recognize. Therefore, we adopt one-half of DRA's requested reduction.

12.3 Educational Services - Step-Up Program

In its original testimony, Edison requested $667,300 for its educational program, Step Up, which it described as an integrated three-part strategy for forming educational partnerships. (The other two parts of the program include shareholder funding and employee volunteer time not funded by ratepayers.) The Step-Up program involves students, parents, teachers, and Edison employees in upgrading education through activities such as mentoring, tutoring, and school assemblies.

DRA agreed with Edison that the Step-Up program is a good social program but did not believe it should be funded by ratepayers because it appeared to be a program in the nature of a charitable contribution. The settling parties agreed with DRA's reduction because the benefits cited by Edison are too difficult to demonstrate and quantify to justify the use of ratepayer funding. We agree with DRA's position.

13. Administrative and General (A&G) Expenses

A&G expenses are expenses not included in a specific functional activity such as production, transmission or distribution. Edison's test year estimate for these accounts was $251.267 million.[62] DRA's comparable estimate was $232.892 million, a difference of $18.375 million after the 1994 evidentiary hearings. The FEA's estimate was $245.548 million, for a difference with Edison of $5.720 million. The settling parties' position is set forth below regarding issues on which Edison and DRA disagreed in the evidentiary hearings. The settling parties agreed with Edison's position regarding issues on which only Edison and FEA disagreed.

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62 This estimate does not include amounts for Account 926 (pension and benefit) and Account 930.200 (RD&D) expenses which are addressed in Sections 14 and 15 of this decision, respectively.

Edison's A&G request also included an estimate of capital expenditures, the majority of which relate to telecommunications and mainframe computing. DRA raised one issue with respect to A&G capital expenses (related to the SCENet project) which is discussed in Section 20.

<u>13.1 Account 920</u>

Account 920 includes expenses associated with the compensation (i.e., salaries, bonuses, and other labor-related expenses, but not including director's fees) of officers, executives, and other utility employees chargeable to the utility and not chargeable directly to a particular operating function. Edison estimated $119.541 million for Account 920 expenses.

<u>13.1.1 Customer Technology Application Center (CTAC) Maintenance Expense</u>

Edison requested a total of $366,560 for expenses associated with CTAC. The total represents $300,000 for maintenance expenses and $66,560 for purposes of posting a security guard at the building. DRA objected to this funding request because Edison booked it in the wrong account (i.e., Edison booked this expense in an A&G account, and DRA claims it should have been booked to a DSM account). Neither DRA witness (the witnesses for A&G and DSM) evaluated the merits of this Edison request. The settling parties agreed that these costs are properly included in A&G accounts and agreed to Edison's recommendation.

DRA did not question the reasonableness of these costs, but merely their reclassification. Therefore, we deny DRA's request for disallowance. In the future, even if DRA believes that a utility has misclassified an expense, DRA should coordinate internally so that one of its witnesses conducts an examination on the merits.

<u>13.1.2 Corporate Communications Survey</u>

DRA maintained that Edison's $67,000 request for an annual study to evaluate the effectiveness of Edison's existing

communication programs should be denied because there was no evidence of ratepayer benefit since the survey focuses on corporate good will and inquiries regarding Edison's advertising.

Edison argued that the survey is broader and would focus on many types of communications such as communications between Edison and its employees, customers, and the media, and is not intended merely to evaluate the effectiveness of its advertising campaigns. Edison further stated that the types of advertising the survey addresses are DSM advertisements which are included in rates. The settling parties agreed to DRA's recommendation because of the survey's focus on image and good will, as well as the survey's vague scope during the test year.

We are not convinced by Edison that we should increase this account to authorize a new, annual survey when Edison has not demonstrated that existing means (i.e., measurement and evaluation studies in DSM; management supervision of employees) are not adequate to ascertain effective communication. Nor are we convinced that the survey would be so narrowly tailored as to provide full ratepayer benefits. We therefore adopt DRA's recommendation.

13.1.3 Regulatory and Policy Affairs

After Edison filed its application, it conferred with DRA's auditor and agreed to a $365,367 reduction reflecting below-the-line treatment for certain lobbying expenses. Edison therefore estimated $11.769 million for this item. DRA's A&G witness recommended an additional $501,930 reduction for activities DRA states constitute lobbying and therefore should not be charged to ratepayers (i.e., they should be booked below the line). The settling parties agreed to Edison's estimates in order to obtain the overall benefits of the settlement.

Edison stated that before an activity is booked below the line as a lobbying expense, the employee must be engaged in activity that influences the decisions of public officials, and the

activities must be unrelated to appearances before regulatory or other governmental bodies in connection with providing information about the utility's existing or proposed operations. Edison stated that discussions with staff members of regulatory agencies would not be classified as lobbying since staff members are not decisionmakers.

Edison and DRA agreed that FERC Account 426.4 defines lobbying activities which should not be funded by ratepayers:

> "This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations."

Account 426.4 describes lobbying expenses as activities conducted for the purpose of influencing public officials' decisions. It does not limit lobbying expenses to those activities occurring directly with public officials. The duties of 24 of the positions which DRA has delineated include contacts with <u>staff members</u> of the regulatory agencies. Edison has not convincingly demonstrated that all these activities fall within Account 426.4's exception. We do not believe that influencing the decisions of public officials through staff members of regulatory agencies should be funded by ratepayers any more than direct contact with these public officials should.

Of the two remaining positions questioned by DRA, Edison states that those positions have contacts with decisionmakers, but those contacts are for the purpose of providing information related

to Edison's existing or proposed operation. Edison argued that DRA's analysis is flawed because it assumes that all costs must be for the purpose of influencing a public official. Similarly, Edison's analysis is flawed, because it assumes all costs incurred by these employees fall within the exception set forth in Account 426.4. Edison has not met its burden of proof in demonstrating a delineation of costs for these two employees as well. We therefore adopt DRA's recommendation.

13.1.4. Law Department Severance Payment

The FEA recommended reducing Edison's Account 920 estimate by $380,292 to remove severance payments made by Edison to law department employees in 1992.[63] According to FEA, a comparison of 1992 nonlabor expenses with expenses incurred during the years 1988 through 1991 shows that Edison's 1992 expenses were significantly higher than those expenses during prior years, and that 1992 severance payments to former employees are primarily responsible for this increase.

Edison disagreed with FEA. Edison stated that although the law department is increasing the total number of employees, the need to terminate attorneys will continue in order to accommodate changing business needs, and due to more stringent performance standards for Edison's attorneys. Because of the risk and uncertainty associated with proving cause in termination cases, Edison believes it is prudent to negotiate a severance agreement with terminated attorneys. FEA disagreed, stating that Edison employees should currently be performing to high standards given the high wages and benefits they already receive, and that the implication of allowing higher test year expenses for severance

63 Edison used a what it terms a budget-based methodology in projecting these expenses, by using 1992 expenses as a base, and adjusting them upward or downward to derive its 1995 request.

payments is that Edison will continue to hire persons who will not meet the established performance standards in future years.

We are not convinced by Edison that these 1992 recorded severance payments are likely to recur in the test year. Therefore, we adopt FEA's recommendation and reduce Edison's test year request by $380,292.

13.1.5 Employee Volunteer Program Expense

The FEA recommended that $87,000 should be deducted from Edison's test-year request for expenses for the employee volunteer program, which Edison describes as a program which coordinates the volunteer efforts of about 3,500 Edison employees. Edison compared the recovery through rates of employee volunteer program expenses with previously authorized Junior Achievement expenses, citing D.92549, 5 CPUC2d 39, 64. Edison believed that the employee volunteer efforts benefit the communities in Edison's service territory, and ultimately benefit Edison's customers.

The FEA argued that since the organizations which Edison employees choose to volunteer their time are selected by the employees, and not ratepayers, these expenses were similar to charitable contributions, and should not be funded by ratepayers.

There is no question that funding an employee volunteer program is a worthy cause. The issue is whether ratepayers should fund this expense. In D.89-12-057, 34 CPUC2d 199, 267, we described "our longstanding policy that ratepayers should not fund discretionary contributions to organizations where they have no voice in selecting the recipients." (See also Pacific Tel. & Tel. Co. v. Public Util. Com. (1965) 62 Cal.2d 634, 669, where the California Supreme Court upheld a Commission decision disallowing rate charges for charitable contributions.) Consistent with this policy, we adopt the FEA's recommendation and reduce Edison's request by $87,000.

13.1.6 High Five Service Program

The High Five Service Program recognizes employees for excellent performance. The FEA recommends that the Commission not fund in rates the $7,100 program costs, since the benefits which Edison states the program will generate do not occur within the test year. The FEA also argues that ratepayers already fund exemplary performance of employees through payment of wages and benefits.

Edison states that the High Five Service Program is a legitimate tool to recognize employees who achieve productivity gains or cost savings and who improve customer service. Edison further maintains that the High Five program replaced a prior quality of service program, and that cost savings from the prior program are reflected in the base year.

The issue is whether the expenses from the prior quality of service program were also removed from the base year. Edison has not demonstrated that they were. We therefore grant the FEA's recommendation.

13.1.7 Employee Meeting Expenses

Edison forecasted $1.4 million for employee meeting expenses in the test year. The FEA recommended that Edison's test year expenses be reduced by $887,149 to eliminate expenses for videoconferencing and floral centerpieces, stating that they are an expenditure of funds for an elaborate purpose with little if any ratepayer benefit.

Edison stated that these expenses are reasonable because they enable Edison's CEO and officers to discuss with employees the operations of the company and answer employee questions, imparting the same message to all Edison employees. Edison described that the CEO and officers are linked to several locations simultaneously so that all of the employees may attend meetings in about three sessions in a week, and that videoconferencing allows Edison to provide a consistent and accurate message to all employees. Edison

requested an increase in its 1993 budget from $943,980 to $1.4 million because it projects more employees will attend the meetings due to the changes in the electric utility industry and its regulation.

Edison has failed to demonstrate that videoconferencing is a more cost-effective method to conduct employee meetings than other existing methods. Furthermore, if it were more cost-effective, Edison should be able to fund videoconferencing within its existing budget. Edison does not address funding for floral centerpieces. We therefore grant the FEA's request.

13.2 Account 921 Office Supplies and Expenses

Account 921 includes office supplies and expenses incurred in connection with the general administration of the utility's operations not specifically provided for in another account or group of accounts. Edison requested $32.123 million for this account.

13.2.1 Association Dues and Membership Expenses

DRA recommended that the Commission reduce Edison's Account 921 request by $101,000 to exclude expenses for certain association dues and membership expenses which DRA states should not be charged to ratepayers. Specifically, DRA recommended that we reject all employee chamber of commerce dues ($82,000) and certain other employee membership dues ($19,000) since such organizations are unrelated to utility business.

Edison stated that chamber of commerce membership expenses serve ratepayer interests, in that they facilitate interaction between Edison employees and its community. This interaction allows Edison to answer questions and impart information about its services and to identify community changes, identify businesses which might be in trouble, and listen to customers' problems and needs. Edison stated that the other organizational membership expenses which DRA contests are also related to the utility's business and that DRA conducted inadequate

review by basing its determination of the title of the organization. The settling parties agreed to DRA's recommended reduction because the record does not sufficiently describe each organization's relationship to utility business and ratepayer benefit.

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

13.3 Account 922

Account 922 includes a credit for a portion of expenses recorded in Accounts 920 and 921 which are transferred to construction costs. In accordance with the FERC Uniform System of Accounts, annual studies should be conducted to determine the portion of Accounts 920 and 921 to be transferred to construction costs. Edison's 1993 study conducted in accordance with the Uniform System of Accounts concluded that an 18% capitalization rate should be used to allocate Account 920 and 921 expenses to construction. DRA agreed with the 18% rate. The difference between Edison and DRA is due to their different recommendations for Accounts 920 and 921, which differences we address above. We therefore adopt Edison's recommended 18% capitalization rate.

13.4 Account 923

Account 923 reflects expenses of professional consultants and others (such as accountants and auditors, actuaries, and attorneys) for general services not specifically applicable to other accounts.

<u>13.4.1 Outside Services Expenses</u>

Edison estimated its expenses for outside services using what it describes as a budget-based methodology using 1992 activities and recorded expenses as a base for test year expenses and then adjusting them to remove the impact of one-time or other expenses that are not expected to recur. Edison removed $3.661 million in nonrecurring expenses from 1992, and states that it did not offset that decrease with increases in outside service expenses in Account 923 or any other FERC account.

DRA recommended that Edison's estimate for outside services be reduced an additional $2.029 million to reflect the impact of what it believes to be additional nonrecurring outside expenses. DRA calculated that approximately 43% of the 1992 recorded costs would not recur. DRA stated that since it is impossible to determine what portion of Edison's $3.7 million reduction is attributable to the elimination of one-time service costs or a transfer to another FERC account, DRA's entire recommendation should be adopted. The settling parties agreed with DRA's recommendation since DRA identified outside services that will end between 1992 and 1995 without corresponding new or replacement activities to justify Edison's request.

We agree with DRA that Edison has not met its burden of proof in justifying its request and therefore adopt DRA's requested reduction.

<u>13.4.2 Medical Clinic and Service Closures</u>

DRA initially recommended that Edison's requested Account 923 expenses be reduced by $1.125 million to reflect savings attributable to the elimination of 15 contract medical workers (receiving compensation of $75,000 per year) due to the closure of three Edison medical clinics in 1993 and the termination of geriatric and laboratory medical services in 1994. DRA also initially recommended that the Commission reduce Edison's Account 935 request by $63,240 to reflect expense decreases it

attributes to lower medical equipment maintenance costs. After the close of evidentiary hearings, DRA and Edison agreed that the proper FERC account in which to reflect this proposed reduction is Account 926 (dealing with health care expenses), but still disagreed on whether this reduction is appropriate.

Edison stated that all health care costs, including costs for contract health care workers, are included in Account 926.1, to which Edison attributed a $789,000 reduction during 1992 to 1994 due to productivity improvements in the clinics (including clinic closures). Edison stated that portions of the costs formerly associated with the closed clinics or terminated services were either transferred to other clinics or outsourced for primary care, that the net savings are reflected in Account 926.1, and any further reductions to that account would double count the savings due to medical clinic and service closures.

DRA disagreed for several reasons. DRA stated that Edison has not presented recorded data to justify its derivation of savings attributable to the elimination of 15 full-time contract medical workers and the termination of services. For instance, Edison could not provide any actual expense for those contract workers between 1986 and 1992, and with the exception of laboratory services, Edison could not provide any record of equipment maintenance costs for the clinics and services of any of the last three years in which expenses were incurred. In lieu of historical recorded costs, DRA estimated an average expense per terminated medical contract worker of $75,000 a year, which it asserts is conservative since eight of the 15 were doctors or consultants who typically receive higher compensation levels. The settling parties agreed that it was difficult to track reduced contract health care personnel expenses associated with the closure of medical clinics and terminated medical services, and compromised by agreeing that the impact of reduced contract positions is included in the $789,000 reduction Edison has already made to this account.

Edison's documentation of its claimed reduction here could have been better substantiated. For example, Edison's reduction of corporate medical expenses by approximately $337,000 resulting from closed clinics and terminated medical personnel appears insufficient, even assuming that the entire $337,000 relates to contract medical workers savings. (See Exhibit 208 at p. 18.) We will therefore reduce Account 926 by an additional $788,000 which is DRA's proposed reduction less $337,000. We believe this is a conservative reduction given Edison's lack of specific documentation (i.e., the lack of actual past expenses for contract medical workers) on this issue.

Edison also disagreed with DRA's proposed reduction of $63,240 due to lower medical equipment maintenance costs. Edison stated that its request includes the impact of reduced maintenance costs for medical equipment which was salvaged or donated, and that most of this equipment did not require special maintenance. The settling parties agreed to Edison's estimate. We believe the reduction we have authorized above is reasonable for this account and do not adopt DRA's recommendation here.

<u>13.4.3 Law Department Displacement Savings</u>

DRA recommended that the Commission reduce Accounts 923, 924, 925, and 928 by $124,000 to reflect additional savings from the displacement of outside counsel that Edison would realize as a result of hiring ten attorneys to its law department between 1993 and 1995. Edison disagreed, stating that its estimated savings includes nine full-time equivalents of new attorneys for 1995 since, in its best judgment, the remaining two attorneys will be hired in mid-year 1995. DRA disputed that Edison has established that these two attorneys will be hired mid-year 1995 and not earlier. DRA also maintained that even if these attorneys are hired mid-year in 1995, the cost savings from 10 attorneys will be in effect for the full rate case cycle. The settling parties agreed to DRA's requested reduction.

Edison has not met its burden of proof in establishing at what point during the test year the two attorneys will be hired. We therefore adopt DRA's reduction.

13.5 Account 924-Property Insurance

Account 924 records costs associated with the amortization of premiums for both general and nuclear property insurance policies, and amounts charged to the property insurance reserve. This account also records the cost of labor and related expense incurred in property insurance activities. Edison originally requested $14.299 million for the test year for this account.

13.5.1 Environmental Cleanup Costs

Edison's estimate for this account included $1.3 million of law department expenses to pursue recovery of environmental cleanup costs from Edison's insurance carriers. After Edison filed its application, the Commission issued D.94-05-020, which adopted a multiparty settlement concerning rate recovery of hazardous waste investigation and remediation costs. Edison therefore withdrew $1.3 million from its request, making its position consistent with DRA and FEA, who also stated that the $1.3 million should be subject to the cost recovery mechanism in the hazardous waste settlement. This account should reflect the $1.3 million reduction.

13.5.2 Other Litigation Expenses

Edison used a five-year average to request $495,000 in test year 1995 for outside counsel expenses for litigating matters in which Edison is a plaintiff primarily related to property damage. DRA recommended that the Commission deny funding of $321,000 which reflect the 1988-1992 litigation costs associated with a case between Edison and Westinghouse which settled in 1993, because Edison failed to support the likelihood of potential similar expenses which would occur during this rate case cycle. The settling parties agreed with DRA's requested reduction since

expenses similar to the settled Westinghouse case would not be representative of similar future litigation costs. We agree with DRA's position and approve its requested reduction.

13.5.3 Blanket Crime Insurance

The FEA recommended reducing Edison's test year expenses by $34,203 because its expense for blanket crime insurance is overstated. The FEA stated that as a basis for developing its expense estimate, Edison assumed that a premium increase would become effective on January 1 of the test year when in reality it would become effective on June 18. We adopt the FEA's recommendation.

13.6 Account 925-Injuries and Damages

Account 925 includes amounts reserved for uninsured losses and the amortized cost of insurance premiums for coverage of losses incurred through claims and suits for injuries and damages to persons and property. It also includes expenses for the settlement of injuries and claims, and the cost of labor and related expenses incurred in injuries and damage. Edison estimated expenses of $31,799,000 for test year 1995.

13.6.1 Medical Malpractice Insurance

The FEA recommended reducing Edison's test year expenses by $19,244 because Edison's premium for medical malpractice insurance is effective on July 1, yet its calculation of the test year claim assumed that any increase of the premium would become effective January 1. This recommendation is similar to the FEA's recommendation on blanket crime insurance, and we adopt this recommendation as well.

DRA recommended reducing Edison's requested expense for medical malpractice liability insurance for the test year by $23,000. DRA's recommendation was based on the reduction of eight of Edison's medical professionals in 1993 and 1994 due to the closure of some medical clinics and the fact that Edison's insurance carrier projects that the elimination of personnel may

decrease the premium by 1% to 3%, yet Edison projects a 10% increase in 1995. The settling parties agreed with DRA's recommendation. Edison did not rebut the facts or rationale underlying DRA's adjustment, which we find reasonable. We therefore adopt DRA's recommendation here.

13.6.2. Directors and Officers Liability Insurance

Edison requested $2.873 million for the test year for Directors and Officers' (D&O) liability insurance premiums to provide coverage for lawsuits brought against the corporation, its officers, directors, trustees, and senior officials. DRA recommended that the Commission deny this request because ratepayer benefits are, at best, indirect. DRA stated that the trend in D&O lawsuits is related to the increasing use of the insurance to benefit shareholders and investors to limit their investment liability. Between 1986 and 1993, there was only one lawsuit (which was settled) involving Edison's directors and officers. This settlement was charged below the line, since it was less than Edison's deductible on the policy. Ratepayers bore $768,000 in defense costs of the suit in addition to the D&O liability insurance premium costs between 1986 and 1993 (about $20 million). DRA therefore urged the Commission to reverse D.87-12-066 and reduce Edison's request by the D&O premium costs. This result would be consistent with a recent case by the Nevada Public Service Commission.

Edison stated that officers and directors can be sued as individuals in connection with their Edison duties not only by shareholders, but also by employees, customers, competitors, and governmental agencies, and that in 1993, shareholder claims represented less than half of all D&O claims in the United States. Edison maintained that D&O insurance is a necessary and reasonable cost of doing business which protects the corporation and enables the company to obtain qualified officers and directors, and that the efficiency of the company may be compromised without such

coverage. Edison stated that the Nevada Public Service Commission's decision is inapposite, since the only coverage provided for by the policy at issue there was for shareholder suits against the officers and directors.[64] The settling parties agreed to allocate the premium cost 50/50 between shareholders and ratepayers since the insurance provides coverage for shareholder lawsuits as well as suits filed by others.

In D.87-12-066, 26 CPUC2d 392, 422, we permitted these types of premiums to be recovered in rates. However, the statistics provided by DRA from 1986 - 1993, which were not available in 1987 when we decided D.87-12-066, illustrate that shareholders also benefit from this insurance. Therefore, we will allow half of the expenses requested by Edison for this item. By making this allocation, we are not implying that it is not necessary for Edison to maintain such insurance. To the contrary, we are funding half of the premium with ratepayer funds. However, to the extent that shareholders also benefit from this insurance coverage, they should also share in the expense.

13.6.3 Injuries and Damages Claims

Edison's test year expense estimate for Account 925 injuries and damages claims is divided between claims department departmental expenses and general expenses. Edison used what it terms to be a budget-based methodology for estimating the departmental expenses and a five-year average for the general expenses for a total request of $8.615 million. DRA recommended that the Commission reduce Edison's request by $156,000, and use a seven-year average to determine the departmental expenses rather than Edison's budget-based methodology. While DRA agreed with Edison that the forecasting method that does the best job of

64 Edison cited In re Sierra Pacific Power Company, Docket Nos. 87-1226 and 87-1227, dated June 24, 1988, 94 PUR 4th at 69.

predicting future expenses should be used, DRA disagreed that forecasting methods within the same department should vary. DRA argued that both departmental and general expenses fluctuate from year to year and thus should be estimated in the same fashion. DRA did not object to using a five-year average to determine the general expenses. Edison continued to support its estimates, stating that the difference in forecasting methods was necessary to produce the most reasonable forecast. Edison alternatively argued that if the Commission adopts DRA's recommendation, it use the same methodology (i.e., either a five or seven-year average) for the account. In its reply brief, Edison argued that a seven-year average should be used, which results in a $300,000 higher estimate than Edison's request for this item. The settling parties agreed with DRA.

Both Edison and DRA find a five-year average reasonable for estimating certain departmental expenses. We agree with DRA that a consistent estimating methodology should, at the very least, be used to determine expenses for injuries and damages claims, and it is difficult for us to apply a budget-based analysis to estimate general expenses. We therefore determine the estimate for both departmental and general expenses using a five-year average, which Edison initially found reasonable for estimating general expenses. Our decision results in a $62,000 decrease from Edison's proposal.

<u>13.6.4 Workers' Compensation Expense</u>

Edison requested $10.404 million in Workers' Compensation expenses for the test year. This is a $1.8 million (or 20%) increase over 1992 expenses. Edison also projected a $1.9 million productivity savings with respect to certain capital accounts as a result of implementing certain computer systems and an accident avoidance program. Edison used a four-year linear trend of recorded costs for 1989 - 1992 to derive its test year estimate. Edison attributed the increased test year expenses to the impact of the 1989 legislation entitled the Reform Act, which it states

accelerated its benefit payments, disability payments, and rates related to workers' compensation and which will continue to drive up expenses during the test year.

DRA recommended that the Commission authorize a test year expense level of $8.641 million, which is the amount of Edison's 1992 recorded workers' compensation expenses. DRA did not believe it appropriate for Edison to use costs from 1989 in its trend analysis, since the 1989 Reform Act did not impact benefit payments until January 1, 1990. Second, DRA claimed that Edison's historical data suggests a leveling or reduction in workers' compensation costs (i.e., while the costs increased between 1990 and 1992, they remained constant between 1991 and 1992). DRA also believed that various measures in the workers' compensation reform legislation of 1993 will cause workers' compensation costs to decline by as much as 14%. DRA stated that the 1993 legislation is only one illustration of the declining trend in workers' compensation costs. Other indicators include the 12.7% decrease in premiums ordered in 1993 by the Insurance Commissioner, information from the California Office of Self-Insurance Plans showing a decline in the number of claims and costs of self-insureds between 1990 and 1991, and information from the California Workers' Compensation Institute showing a decline in the frequency of workers' compensation claims in the market.

Edison argued that its four-year trend should not be rejected for including 1989 data, because the 1989 act increased costs. Moreover, Edison stated that because it is self-insured, it will not experience the 14% savings from the 1993 legislation. For example, Edison stated that it will pay increased benefits, but will not experience a decrease in insurance premiums since it is self-insured. Edison also stated it does not anticipate impact from medical treatment reform, vocational rehabilitation cost caps, and post-termination and psychiatric reforms. Edison also argued that insurance industry data cited by DRA does not indicate the

cost trends of self-insured companies. The settling parties agreed to adopt Edison's estimate of these expenses. In Edison's opinion, worker's compensation benefits and other costs for self-insured companies like Edison will not be offset by decreases from workers' compensation reform acts. DRA stated it reached this agreement because the precise impacts of the 1993 Reform Act on self-insured companies may be difficult to predict with certainty.

At the settlement hearings, TURN also recommended a $1,349,000 reduction for this account to reflect lower trends in the escalation of these costs as well as a small adjustment to reflect cost reductions from the 1993 statute. Edison opposed TURN's request, stating again that Edison's methodology for cost computation is reasonable and that Edison does not anticipate cost decreases as a result of the recent workers' compensation legislation.

Workers' compensation costs have been fluctuating for the last several years. However, we find it difficult to determine the best method for estimating expenses in the test year because it is difficult to determine the effects of the 1993 reform legislation on Edison's workers' compensation costs.

Edison's Chairman of the Board and Chief Executive Officer, Bryson, explained that Edison loaned its Manager of Workers' Compensation "to the legislature's highly successful year long effort to reform the State's workers' compensation system." (Exhibit 1 at p. 5.)[65] Thus, it is reasonable to conclude that Edison should experience at least some cost control as a result of the "highly successful" 1993 legislation. However, given the fluctuation of costs over the past years and Edison's demonstration that its 1991 and 1992 workers' compensation costs were lower than

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65 Edison described the 1989 legislation as "so ineffective that an additional reform act was needed just three years later." (Edison Opening Brief at p. 244.)

several other regulated utilities, we do not believe it is reasonable to adopt DRA's recommendation of utilizing 1992 recorded data or TURN's recommendation. Rather, we believe it reasonable to adopt Edison's estimate.

13.6.5 Palo Verde Injuries and Damages Reserve

Edison requested $149,000 for the test year for an injuries and damages reserve in connection with Edison's share of the Palo Verde Nuclear Generating Station. DRA initially recommended that the Commission deny this request based on inadequate documentation, but later withdrew its opposition in light of more extensive rebuttal testimony filed by Edison. We therefore adopt Edison's request here.

13.6.6 Expenses Related to Discrimination Lawsuits

DRA recommended a reduction of $2.03 million from Edison's base A&G expenses for Account 925 before the A&G accounts are trended because Edison charged ratepayers for the settlement of a discrimination lawsuit. DRA based its recommendation on FERC Accounting Release (AR-12) and Commission decisions which direct a utility not to charge ratepayers for settlement costs of a suit alleging discriminatory employment practices. Edison stated that FERC AR-12 should not be applied in this case involving a settlement because such an application discourages settlement and encourages litigation. Additionally, Edison stated that if the Commission agrees with DRA, DRA's $2.03 million disallowance is in error. Rather, Edison believed that proper implementation of DRA's recommendation should result in one-third of the $2.03 million (approximately $667,000) being applied to each of the years 1990 through 1992, with a disallowance of about $600,000 in the test year. The settling parties agreed to a reduction of $588,000 on the basis that DRA's recommended reduction should apply to recorded adjusted data before trending.

In D.92549, 5 CPUC2d 39, 64-65 (1980), we excluded from the test year results all costs which Edison incurred in an

affirmative action suit which we assumed would shortly be settled, explaining our position was in harmony with FERC in AR-12. AR-12 provides that the proper accounting treatment for expenditures made by the utility which result from employment practices that are found to be discriminatory by a judicial or administrative decree or that are the result of a compromise settlement or consent decree are as nonoperating expenses (i.e., not chargeable to ratepayers). AR-12 reasons that "[e]xpenditures of the nature mentioned above that can be readily identified and quantified should not be considered as just and reasonable charges to utility operations..."

We agree that our prior Commission precedent and FERC AR-12 should be applied to this case. Although we support alternative dispute resolution in appropriate situations, one of the policies behind AR-12 is that costs incurred in meritorious employment discrimination suits should not be charged to ratepayers. If we reversed this long-standing policy, we would be sanctioning ratepayer funding of these types of costs, provided a settlement occurred. Furthermore, we believe that altering the existing policy may send the wrong message that it is not necessary for the utility to be vigilant in its employment practices. We therefore decline to reverse this policy.

Edison stated that if we grant DRA's recommendations here, DRA has incorrectly calculated the appropriate disallowance. According to Edison, if DRA's three years of costs are applied to Edison's recorded-adjusted data before trending, the appropriate disallowance is not $2 million, but one-third of $2 million, or $667,000. (Edison stated that after trending, DRA's recommendation produces a disallowance of about $600,000, but DRA's recommendation was to make this adjustment before trending.) We therefore disallow $667,000 of Edison's request in Account 925 for expenses related to discrimination lawsuits.

13.7 Account 927-Franchise Fees

Edison developed its recommended franchise fee factor of 0.8375% through linear trending of recorded 1986-1992 franchise fee factors. Edison stated that the upward trend in the franchise fee factor is driven primarily by new incorporations in its service territory. Edison noted that 19 incorporations occurred between 1986 and 1992, and 16 communities are currently considering incorporation. DRA endorsed Edison's estimate.

FEA claimed that Edison's linear regression overshoots the mark, because no new incorporations took place in calendar years 1992 and 1993, and none had occurred to date in 1994. (Exhibit 208 at p. 36:8-18; R.T. Vol. 49 at pp. 5610:12-13.) According to FEA, a test year franchise fee factor based on an assumption of new incorporations would be speculative. FEA instead proposed scaling up the recorded 1992 franchise fee factor (0.8048%), employing Edison's own estimate of the proportion of growth in the franchise fee rate attributable to all causes other than new incorporations. Using this approach, FEA calculated its recommended factor of 0.8087%.

Edison responded that its linear trend already accounts for two years (1986 and 1982) with zero incorporations, and that it is impossible to know with certainty how many communities contemplating incorporation will ultimately incorporate, or even precisely how many communities are considering incorporation.

The settling parties adopted Edison's proposed factor of 0.8375%, on which "Edison and DRA continue to agree." (Settlement Joint Comparison Exhibit at p. 77.)

In response to a request by the assigned ALJ during settlement hearings, Edison provided Exhibit 234, which shows that no new incorporations took place in 1994, and none to date as of April 1995. Since the level of incorporations has quite clearly plateaued over a very broad time range, extending from 1992 well into test year 1995, we are persuaded to follow FEA's recommended method, and adopt the resultant franchise fee factor of 0.8087%.

We also correspondingly adjust the Net-to-Gross Multiplier to reflect our adopted franchise fee factor, as shown in Appendix D.

13.8 Account 928-Regulatory Commission Expenses

Account 928 includes expenses incurred in connection with formal cases, hearings and investigations before regulatory commissions (except pay of regular employees only incidentally engaged in such work). At the close of the 1994 evidentiary hearings, Edison requested $7,077,000.[66] Both DRA and FEA recommend reductions to this account.

13.8.1 Outside Counsel-Regulatory Commission Expenses

Edison requested $6.673 million for its test year expenses for outside counsel expenses related to proceedings before various regulatory agencies, including the CPUC. Edison made this calculation by averaging two years worth of expenses, $5,087,000 for 1991 and $10,088,000 for 1992. DRA recommended the Commission reduce Edison's test year forecast by $1.970 million to exclude costs associated with two Commission proceedings (the Mohave Coal Plant Investigation, I.86-04-002, and the Palo Verde Nuclear Generating Investigation, I.89-12-025). The FEA recommended the Commission disallow $777,284 by using a three-year average including 1993 data instead of a two-year average. The amount incurred by Edison in 1993 was $5,332,147.

Edison did not dispute that both the Mohave and Palo Verde proceedings will probably have concluded before the test year but states that these costs should be included in Edison's two-year average because they are representative of costs that may occur in the future due to, among other things, the Commission's

66 This request reflected a reduction of $265,000 for compliance expenses related to conditions outlined in the issuance of FERC licenses of Edison's hydro generation plants and water storage facilities, which Edison made after reviewing DRA's recommendations.

investigation into the electric industry restructure. Edison argued that since the 1993 recorded costs do not take electric industry restructure into account, the Commission should also deny FEA's request. The settling parties agreed to a compromise, reducing Edison's original estimate by $689,000, which reflects a reduction for the expenses related to the Mohave investigation which the parties do not expect to recur. As part of the compromise, the settling parties agree to the Palo Verde expenses since it is unclear whether these costs will recur in the future. At the settlement hearings, TURN advocated DRA's original litigation position.

We agree with DRA's original litigation position and TURN that the Mohave and Palo Verde costs are one-time expenses which will likely not recur. The Mohave costs were associated with an accident in 1985 and the Palo Verde costs were associated with outages in 1989. Furthermore, in the past several years we have experienced an increase in settlements and stipulations which, together with changes anticipated in our investigation on electric industry restructure, might streamline regulation. (See, e.g., D.93-12-043 slip op. at p. 74.) We therefore adopt DRA's and TURN's recommendation. Additionally, we reject DRA's recommendation that Edison should track its annual expenses in the separate categories of labor, nonlabor, and other expenses in a report to the Commission. DRA states that Edison already reports certain proceeding costs to FERC on Form 1 on an annual basis. Edison should provide this information to DRA upon request as appropriate in future proceedings. However, we do not see the need to institute an additional reporting requirement.

13.8.2 Regulatory Policy and Affairs' Regulatory Commission Expense

Edison proposed $220,000 for Account 928 for regulatory and policy affairs, which is less than half the recorded and adjusted amounts for 1992. At the time it filed its application in this case, Edison based its estimate on the expected level of participation of Edison personnel in regulatory proceedings in 1993. FBA recommended that the test year estimate be set equal to actual 1993 recorded expenses, which are $106,000 rather than $220,000. Edison argued that the FBA has selectively made this recommendation in instances where Edison's recorded data is lower than estimated 1993 expenses, but has not made such a recommendation when 1993 recorded data is higher than recorded expenses. We agree with Edison that a selective use of 1993 recorded data is inappropriate here and therefore adopt Edison's proposal.

13.9 Account 930.1-General Advertising Expense

Account 930.1 contains labor and nonlabor expenses incurred in certain informational advertising and related activities not charged to other accounts. Edison forecasted $618,000 for general advertising expenses.

13.9.1 Advertising Manager

Edison requested $68,000 in the test year for its advertising manager's salary. DRA recommended a reduction of $23,000 to reflect the portion of the advertising manager's salary formerly related to conservation duties in Account 909.1, since DRA understood that the advertising manager was performing fewer duties than in 1992. Edison explained on rebuttal that the advertising manager is fully employed, in that, following the company reorganization, he assumed additional job duties of managing a new minority/Spanish language communication program which did not exist in 1992. The settling parties agreed with DRA's requested reduction.

Edison's explanation is reasonable and we will allow $68,000 for this item. However, in the future, Edison should more completely justify requests such as this in its direct showing and not wait until rebuttal to do so.

13.10 Account 930.2 Miscellaneous General Expenses

Account 930.2 includes the cost of labor and expenses incurred in connection with the general management of the utility not included elsewhere. Edison forecasted $14,311,000 for miscellaneous general expenses in the test year, excluding RD&D costs which we address in Section 15. We also addressed the issue of COT project costs in Section 8.

13.10.1 Directors' Pensions

Edison requested $940,000 associated with its Board of Directors' pension plan. DRA and FEA both separately recommended that this expense be rejected in its entirety. The settling parties agreed with DRA. We agree with DRA and FEA.

In Edison's last general rate case, we denied Edison recovery of these expenses. (See D.91-12-076, 42 CPUC2d 645, 689-690.) We are not persuaded by Edison that our prior decision should be reversed here.

13.10.2 Directors' Fees and Retainers

Edison requested $607,000 for the test year for Directors' fees and retainers, which it states are necessary for attracting well-qualified individuals to serve on its Board of Directors. DRA agreed with the total amount of the request, but disagreed with the allocation method between Edison and SCEcorp, Edison's parent corporation. DRA proposed a 50/50 split of these expenses between ratepayers and shareholders reflecting the proportional time the directors spend on each entity's business. DRA and Edison agreed that the allocation of money occurs in ECAC proceedings, and consequently, Edison argued that no reduction is appropriate in this proceeding. DRA agreed to withdraw its request, provided the Commission modified D.88-01-063

with respect to allocating directors' fees so that 50% is allocated to the BRAM balancing account. DRA believed that this would best incorporate the change in allocation adopted in Edison's last general rate case, D.91-12-076. Edison disagreed, and states that D.91-12-076 did not modify D.88-01-063. The settling parties agreed with Edison's request.

Actions taken or items discussed at a board meeting may involve issues that affect each entity, and we decline, based on the record in this case, to modify the multifactor formula we set forth in D.88-01-063, 27 CPUC2d 347, 388, which we use to allocate directors' fees. We therefore deny DRA's request.

13.10.3 Miscellaneous Directors' Expenses

In its direct testimony, FEA recommended that $30,000 be removed from Edison's test year for directors' expenses relating to interest on the Director Deferred Compensation Plan. The FEA later stated that it was satisfied that Edison removed these expenses from its current revised request. Therefore, FEA withdrew its recommendation.

13.10.4 Dues and Membership Expenses

DRA recommended a $74,690 reduction for corporate chamber of commerce dues. DRA also requested a $25,006 reduction of other corporate association dues. The settling parties agreed to this reduction since the record does not sufficiently describe each organization's relationship to utility business and ratepayer benefit. For the reasons set forth in our discussion regarding Account 921, we grant DRA's request.

DRA also requested a reduction of $264,500 for dues for the Nuclear Management and Resource Council (NMRC). Edison disagreed, arguing that this organization has members possessing expertise in fields needed by Edison employees and serves to educate Edison employees on various issues. Edison alternatively argued that if the Commission were to accept DRA's recommendation, DRA's reduction is in error because it double-counts NMRC dues.

Edison stated that only $126,000 is attributable to NMRC dues for the test year. The settling parties agreed on a $126,000 reduction of Edison's estimate because the record does not sufficiently demonstrate the ratepayer benefit associated with NMRC membership.

In D.91-12-076, 42 CPUC2d at 689, we denied Edison recovery for NMRC dues and rejected "Edison's conclusion that the NMRC's purpose excludes advocacy." We are not convinced by this record that the NMRC's purpose has changed since Edison's last general rate case. We therefore adopt the $126,000 reduction.

Edison requested $617,886 for its test year expense for Edison Electric Institute (EEI) dues. Edison's request reflected a 14.03% reduction from the full amount of the dues to remove the estimated amounts for legislative advocacy and contributions and club dues. DRA recommended reducing this amount by $173,409 to exclude additional amounts for regulatory advocacy, legislative policy research, public relations and advertising. The FEA recommended reducing this amount by $70,299 to reflect a reduction for legislative policy research, institutional advertising, and contributions and club dues. DRA's and FEA's requests overlap in part. The settling parties agreed to DRA's recommended disallowance because the lobbying activities DRA alleged related to EEI dues were difficult to quantify and arguably subject to interpretation.

In D.89-12-057, 34 CPUC2d 199, 266-269, the Commission denied authorization of ratepayer funding for the portion of the EEI dues which relates to legislative policy research, legislative advocacy, contributions and club dues. The Commission examined National Association of Utility Regulatory Commissioners (NARUC) 1987 audit report in order to determine whether certain portions of PG&E's EEI dues should be funded by ratepayers.

> "Legislative Policy Research. While it is possible that this account could include research not intended to influence legislation, the account is not defined in this manner. In fact, the account is defined to include general expenses associated with the general support of legislative advocacy. The account also includes all expenditures of a general political nature, such as grass roots organizing, if such activities are not related to a given piece of legislation. As defined by NARUC, this category clearly includes general costs of lobbying.
>
> Regulatory Advocacy: ... Again, the NARUC definition of this expense category does not limit the account in the manner described by PG&E. Instead, NARUC defines the category as including expenses intended to influence regulatory actions, i.e. lobbying expenses:
>
> > 'Regulatory Advocacy - The cost of all written and oral communications with Federal or State regulatory agencies intended to influence the actions of such agencies and the cost of other expenditures which contribute in a general manner to furthering an EEI position on a regulatory or administrative matter.'" (34 CPUC2d at 267.)

On Edison's cross-examination of PRA's witness, Hugh Larkin, he stated that the 1992 NARUC audit report concluded that the legislative policy research does not include costs for legislative advocacy. However, a copy of this section of the audit report is not in the record, and it is unclear if this category contains, for example, expenses for grass roots organizing or other general costs of lobbying previously included. We therefore exclude the portion of EEI dues related to legislative policy research and regulatory advocacy from Edison's test year expense.

We also exclude the portion of EEI dues related to institutional advertising and public relations, which include activities associated with public opinion research seeking to

enhance the image of EEI and its member companies, because this type of advertising does not fall within the types of advertising we permit ratepayers to fund. (See D.86794, 81 CPUC 49, 79 (1976).) We are persuaded by the FEA that we should not indirectly approve ratepayer funding of activities through the EEI which we would not approve if Edison were to directly incur these expenditures.

We make this determination notwithstanding D.92-12-057, 47 CPUC2d 143, 212-213, where we authorized PG&E's estimated test year expense for EEI dues. Our discussion in D.92-12-057 focused on the specific factual circumstances of that case and did not include the type of detailed analysis of appropriate expense reductions for lobbying or advertising as set forth in D.89-12-057 and in this decision. We do not agree with FEA that the EEI dues should be reduced for the amount attributable to contributions and club dues, because Edison has reduced the dues for these items. We therefore reduce Edison's requested amount by $173,409.

13.11 Account 935-Maintenance of General Plant

Account 935 includes expenses for maintaining the general office, communications equipment, and other general plant. Edison estimated a test year expense of $15,556,000 for Account 935.

13.11.1 CTAC Maintenance Expenses

DRA recommended that Edison's $200,000 estimate for maintenance at the Gateway-Birtcher facility be rejected on the grounds that the facility is a DSM facility and these expenses should have been booked to the DSM accounts. Yet, DRA did not make a corresponding adjustment to the DSM account, or discuss the substance of why we should deny Edison's request. The settling parties agreed with Edison's request. For the same reasons set forth above with respect to DRA's similar request in Account 920 we deny DRA's recommendation.

13.11.2 Intermediate Processing Centers (IPCs) and Remote Terminal Units (RTUs) Technician Expenses

DRA recommended that we eliminate $17,000 labor and $9,000 nonlabor expenses for technician expenses associated with maintaining additional installations of IPCs and RTUs because there is insufficient record evidence that technician expenses will increase even if IPCs and RTUs increase. The settling parties agreed with DRA. We agree with DRA and adopt its recommendation here.

13.11.3 Account 935-Reserve Costs

Edison requested $1.0 million related to a reserve for uncollectible accounts receivable and property damage based on a seven-year average, because it believes the maximum data should be used to forecast reserve costs in that it provides the most observations and captures the wide fluctuations inherent in these expenses. DRA recommended a $442,000 reduction by using a four-year average. DRA believed its average is more appropriate because Edison's method captures extraordinary expenses such as earthquake damage not typically included in historical data for ratemaking. The settling parties agreed with Edison's recommendation.

We have established a Catastrophic Event Memorandum Account (CEMA) by Resolution E-3238 for a utility to record costs of, among other things, repairing, replacing or restoring damaged utility facilities caused by certain disasters and to subsequently seek rate recovery. The CEMA account is used by utilities to record certain extraordinary expenses, such as those resulting from large earthquakes. Therefore, we do not think it necessary to include these types of extraordinary costs in determining a reasonable amount for Account 935 reserve costs. We therefore adopt DRA's four-year average in this instance, because this methodology excludes not only two high years of expenses attributable to earthquake damage costs but also one

extraordinarily low year of expenses. We therefore reduce Edison's request by $442,000 for this account.

13.11.4 Electric Power Maintenance

DRA recommended that the Commission reduce Edison's $1.211 million request for maintenance of general plant related to the Electric Power Department by $21,000 (to $1.190 million) to correct a double counting of certain expenses. Edison agreed. Therefore, we adopt $1.190 million forecast.

13.12 A&G Capital Expenditures

No party opposed Edison's forecast of $304.0 million for A&G capital expenditures, the majority of which relate to telecommunications equipment and mainframe computing. Since there is no opposition to this request, we adopt it.

14. Account 926-Pensions and Benefits

Account 926 includes expenses for health care, non-health care (disability, group life insurance, 401(k) savings plan, etc.), post-retirement benefits other than pensions (PBOP), and employee pensions. In this section, the monetary amounts are presented in 1995 dollars (before capitalization) for convenience of discussion.

14.1 Positions of Parties - Prior to the Settlement

14.1.1 DRA

DRA claimed that Edison's health care expense forecast ignored emerging cost trends in Edison's market. DRA suggested, for example, that since the California Public Employees' Retirement System (CALPERS) reported an overall premium reduction for 1994-1995, Edison should have bargained more aggressively for lower cost contracts.

DRA alleged that Edison's reliance on Coopers & Lybrand for consulting help produced an unverifiable "black box." DRA proposed that a fairer approach would be to utilize the Data Resources Incorporated (DRI) forecast of the Employer Cost Index for All Pensions and Benefits -- All Private Industry (ECIBPNS), an index published by the U.S. Bureau of Labor Statistics (BLS). The

DRI forecast estimated an average annual increase in ECIBPNS of 5.15% for 1994-1995 (compared with Edison's overall health care escalation rate of 9.40% for the same period). DRA urged the Commission to apply this forecast to all Benefits except PBOP and pensions, i.e., to the sum of health care and non-health care costs in Account 926.1.[67] DRA claimed this approach was validated by the strong statistical correlation (an "R-Squared" value close to 1.0) between the ECIBPNS index and Edison's costs.

The impact of DRA's recommendation was to reduce Account 926.1 expenses by $9.3 million for health care and $0.6 million for nonhealth care.[68] DRA did not dispute Edison's estimates for PBOP (Account 921.15) and employee pensions (Account 921.2).[69]

14.1.2 Edison

Edison stated that its medical expenditures are directly affected by the steady rise in national health care costs, and will continue to rise at a rate higher than the general inflation rate due to factors beyond Edison's control. Edison said it developed its health care request by relying on a combination of national trends and company-specific health plan information, using a fully documented and reproducible methodology.

In Edison's view, DRA's proposal suffered from the fatal flaw that ECIBPNS is both overinclusive and underinclusive of Account 926 expenses, and would have been applied indiscriminately both to health care and non-health care expenses. Of the

67 In lieu of the standard 1992 base, DRA applied the forecast to Edison's 1993 recorded costs, which by then had become available.

68 A separate DRA proposal to disallow certain miscellaneous nonhealth care expenses is addressed in Section 14.4.

69 DRA's calculation for Pensions and Benefits Paid/Charged to Others (Account 926.3) differed from Edison's, but DRA gave no explanation for this difference.

benefit categories included in ECIBPNS, only four are recorded in Account 926, accounting for only 27% of the total weight of the index. Moreover, several categories of Account 926 expenses are missing from ECIBPNS altogether.

Edison argued that examination of specific components of ECIBPNS very strongly supports its forecast. In particular, the "Health Insurance" subindex of ECIBPNS grew at a 9.4% rate from 1990-1992, closely matching Edison's own 1989-1993 growth rate of 9.0%, and exactly equaling the annualized rate of escalation from 1993 recorded costs to Edison's estimate for test year 1995.[70] Since the Health Insurance subindex was not developed until 1990, Edison also provided the 1986-1992 annual rate of increase for the "All Insurance" category (over 90% of which is comprised of health insurance items). This rate of increase was 8.7%. Thus the annual rates of growth for Edison's recent recorded and forecast test year 1995 health care costs were very closely bracketed by the escalation rates of the two most relevant subcomponents of ECIBPNS which track national health care costs.

Edison further argued that DRA misinterpreted its own statistical results. In effect, DRA mistook regression analysis for correlation analysis: the fact that two variables are highly correlated does not imply they are equal; one may simply be increasing at a faster rate than the other. Edison pointed out that DRA's "R-squared" statistic of 0.967 is actually the output of a linear regression of Edison's recorded 1986-1993 Account 926.1 costs (the "dependent," or predicted variable) against the corresponding ECIBPNS values (the "independent," or explanatory variable). Edison used the regression equation intercept and

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70 The ECIBPNS data series actually runs from March 31, 1991 through March 31, 1993. The time series terminating on March 31st of a given year is taken as representative of the prior year's increase.

estimated slope coefficient of the explanatory variable EOIBPNS (1.797), to derive a predicted 1995 Account 926 value of $198.9 million, very close to its request of $201 million. Thus DRA's regression results actually corroborated Edison's forecast.

Edison disputed DRA's contention that a company with only 55,000 covered lives can exercise market power comparable to CALPERS, with approximately 926,000 covered lives.

14.2. The Settlement

14.2.1 Settling Parties' Agreement

DRA agreed to abandon its proposed EOIBPNS index approach, since "a linear regression analysis of recorded Account 926 expenses... tended to corroborate Edison's 1995 estimate." (Settlement Joint Comparison Exhibit at p. 118.)

14.2.2 TURN's Proposals

At the settlement hearings, TURN called for two adjustments to Account 926. First, TURN recommended updating the trend rates Edison employed to estimate its medical expenses with more recent -- and lower -- trend percentages. Arguing that Edison's assumptions regarding health care cost escalation have "been completely overtaken by events," TURN's alternative health care budget is $12.2 million lower than Edison's.

TURN's recommendation for health maintenance organizations (HMO) is based upon Edison's recorded 1993-1994 percentage changes as given in DRA's pre-settlement testimony. For most other insurance categories, TURN endorsed the trend numbers used by PG&E in the workpapers of its current general rate case (A.94-12-005). Asserting that Edison failed to account for the 67% reduction in retiree health premiums at age 65, TURN also recalculated Edison's PrimeCare budget. Finally, TURN recommended amortizing administrative costs over a six-year period to smooth out "one-time" expenses from implementing new health plans. TURN's health care budget was calculated using all of Edison's assumptions

regarding health plan structure and enrollment. TURN varied only the 1993-1995 trend rates for the various health care categories.

TURN asserted that more recent trend rates borrowed from a neighboring utility within the same state have greater probative value than Edison's older, national trend data, and that Edison presented no evidence that technical differences between Edison's and PG&E's health plans affect the underlying rate of health care inflation. Moreover, any such differences almost certainly would be more pronounced nationally than interregionally.

In supporting this proposal, TURN pointed to the consistent success which CALPERS has enjoyed in its health plan negotiations in recent years: a small increase (only 3%) in 1991-1992, no increase for 1992-1993, small decreases (up to 1.7%) in 1993-1994 and 1994-1995, and (as of submission of Phase 1 of this proceeding) on the threshold of a significant decrease for 1995-1996. (Exhibit 760 at p. 27, Appendix C.) TURN reasoned that Edison's request for continuing increases of up to 10% per year lacks credibility in the face of CALPERS' consistent success, even when due allowance is made for Edison's allegedly smaller profile in the insurance market.

TURN's second adjustment to Account 926 was to increase (from 8% to 9%) the earnings rate Edison assumed in calculating the PBOP revenue requirement. TURN stated that this would save ratepayers an "unknown but significant" amount. TURN, however, neglected to brief this issue. Based on the record, we do not find TURN's recommendation here persuasive and reject it.

14.2.3 Edison's Response to TURN

Edison did not address the merits of TURN's health care proposal in its settlement rebuttal testimony, but at hearings and in its briefs challenged the recorded Edison HMO trends which TURN borrowed from DRA, claiming that TURN hastily accepted them without verifying their accuracy. Edison further argued that for reasons of geography, demographics, and health plan program differences,

PG&E's workpapers have no relevance to Edison's costs. Edison claimed that TURN's PrimeCare calculation double counts "already adjusted" data, and stands by its administrative cost estimate, given that the Company will be negotiating and implementing new plans over the rate case cycle.

14.2.4. Additional Health Care Evidence

During settlement hearings Edison submitted several exhibits in response to the ALJ's request to provide information on recent developments in health care economics, including the announcement of a 1994 Foster Higgins national health care cost survey superseding the 1992 study Edison had employed in its case-in-chief, and the activities of a private-sector health insurance buying coalition known as the Bay Area Business Group on Health (now the Pacific Business Group on Health). Edison also provided the Company's 1994 recorded health care costs and recent enrollment breakdowns by health plan type.

1994 Foster Higgins Study

Edison provided the executive summary and press release (issued February 14, 1995) of Foster Higgins' 1994 nationwide health care cost survey of about 2,100 employers. (Exhibits 218, 219.) The survey reports that due to "an unprecedented increase in managed care enrollment," which was aided by "relatively low medical cost inflation," U.S. employers "successfully drove down their overall health benefit cost" in 1994. "This marks the end of two decades of health benefit cost increases that have consistently outpaced inflation." The average drop in the total health benefit cost was 1.1%, large employers (500 or more employees) realizing a decrease of 1.9%. The Northeast saw a 9.7% decline, while in the

western U.S. (where managed care enrollment already was relatively higher than other regions), the average cost rose a modest 2.0%.[71]

The sudden and unexpected flattening of costs in 1994 "was driven by the biggest increase in employee enrollment in managed care plans in the nine-year history of the survey." The Northeast saw a spurt in managed care enrollment from 34% of total health plan enrollment to 63% between 1993 and 1994, while the corresponding change on the West Coast was less pronounced, from 72% to 80%. HMO enrollment in the West increased from 31% to 41% of total enrollment during the same period. The study is agnostic regarding the outlook for the future: "A large part of employers' favorable experience in 1994 is a one-time savings due to moving employees from a higher cost plan to a lower cost plan, but continued refinement of managed care programs has the potential to deliver long-term savings."

<u>The Pacific Business Group on Health</u>

The Pacific Business Group on Health is a coalition of several large employers (comprising over 300,000 employees of firms such as Bank of America, Pacific Telesis and Safeway Stores) which during 1994 negotiated premium reductions (under a standard health plan design) with 15 HMO's averaging 9.2%, effective January 1, 1995. At that time the coalition was known as the Bay Area Business Group. Edison joined the coalition in November 1994, which then assumed its present name.

<u>14.2.5 Edison's View of Additional Health Care Evidence</u>

The ALJ inquired of two Edison witnesses as to whether, in light of the additional evidence on health care costs, they still believed Edison's test year 1995 health care recommendation

71 The study indicates that the Los Angeles metropolitan area showed a 0.1% decrease, but results for metropolitan areas and states are deemed to be not as statistically robust as the regional and national results.

as set forth in the settlement to be reasonable. Both witnesses answered affirmatively.

Coopers & Lybrand partner John Bertko opined that the 1994 Foster Higgins study "in general supports Edison's recommended funding level; in particular, the one-time migration to lower cost health plans noted by the study has occurred gradually in California, which "added these same relatively small percentages each year until we now have a great bulk of our population in tightly managed HMOs." (R.T. Vol. 58 at pp. 6606-6607.) Bertko stated that while Edison's participation in the Pacific Business Group for Health should pay off "over a period of time," it would not affect his recommendation in this proceeding.

Edison Vice President John Fielder seconded Bertko's opinion, and commented that Edison's recorded expenditures to date for 1995 were "on target" with the Company's prior projections. Fielder added that even without a PBR mechanism in place, "it would be very difficult in today's environment with the pressure on rates to continue to argue for health care increases that go much above the general inflation level. So let me just make policy on the stand and say we will not seek special attrition for health care if in fact...we have to negotiate an attrition mechanism for 1996." (R.T. Vol. 59 at pp. 6756-6758.)

In its settlement briefs, Edison argued that its 10.7% annual growth rate for recorded 1992-1994 HMO costs corroborates the reasonableness of its 9% HMO trend rate assumption. According to Edison, this assumption is also supported by the nationwide 9.7% HMO cost hike for 1993-1994 for large employers reported in the 1994 Foster Higgins study. Edison further argues that its overall 1995 health care estimate is corroborated by the close match between 1993-1994 estimated and recorded values.

14.2.6 TURN's View of Additional Health Care Evidence

TURN stated that the new evidence supports its proposal. TURN was critical of Edison witness Bertko's contention that the

new information has little relevance to Edison's costs, stating that Edison's recent figures on its health plan enrollment breakdown indicate that, contrary to Bertko's description of the situation for California as a whole, Edison's migration to HMO's is only happening now. (Exhibit 233.) TURN disputed Edison's 10.7% figure for its 1992-1994 annual HMO cost escalation, asserting that when updated to reflect Edison's 1995 HMO cost estimate and properly adjusted for net in-migration to HMO plans, Edison's actual per-subscriber growth rate was just 1.4%.

14.3 Discussion

14.3.1 ECIBPNS Index Approach

Edison's pre-settlement rebuttal testimony proved that DRA misconstrued the statistical relationship between ECIBPNS and Edison's recorded Account 926.1 costs. (Exhibit 201 at pp. 17-23.)[72] We cannot, however, endorse Edison's conclusion that the linear regression results confirm Edison's test year estimate. Econometricians universally caution that regression analysis presumes an *a priori* hypothesis of a plausible causal relationship. Edison's demonstration that the composition of ECIBPNS meshes poorly with the elements of Account 926.1, is reason

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72 Elementary econometrics textbooks are careful to highlight the distinction between correlation and regression analysis. (See, for example, Pindyck & Rubinfeld, Econometric Models and Economic Forecasts (1981), at pp. 64-65.) "R-Squared" is not just a correlation measure, but a regression statistic which gauges the explanatory power of a hypothesized causal functional relationship: one or more explanatory (independent) variables are assumed to cause the observed pattern of the predicted (dependent) variable. For this reason, "R-Squared" is denoted the "Coefficient of Determination." Thus DRA's belief that its "R-Squared" result does not presume a cause-and-effect functional relationship is mistaken. (R.T. Vol. 37 at p. 4233.) Edison correctly noted that DRA was not cognizant of the fact that the regression intercept and estimated slope coefficient -- not the value of "R-squared" -- are the ingredients which yield a prediction of Account 926.1 costs. (Exhibit 201 at p. 19.)

enough to dismiss its predictive relevance. More fundamentally, a historical index number approach is incapable of reflecting major shifts in cost trends.

14.3.2 Additional Health Care Evidence

The additional evidence on health care costs introduced at the settlement hearings indicates a halt to two decades of runaway health care inflation. The question thus becomes: what is the significance of this turn of events for Edison's Health Care budget?

Edison's conclusion is that these developments ultimately have no bearing on the determination of its test year 1995 expense level - is unpersuasive.

TURN correctly points out that Edison is only now showing movement toward large-scale HMO enrollment. Edison's overall percentage of subscribers in HMO's has increased from 23% in 1994 to 39% for 1995. But in 1994, according to the Executive Summary of the 1994 Foster Higgins study, 41% of employees in the West were already enrolled in HMO's. (Exhibit 218 at p. 3.) Moreover, the Foster Higgins Press Release shows that among large employers (500 or more employees), 62% of employees -- both in the Los Angeles metropolitan area and the entire state of California -- were enrolled in HMO's.[73] The 1994 Foster Higgins study cites the movement of retirees into HMO's as one of the significant factors driving the end of the cost spiral. (Exhibit 218 at pp. 4-5; Exhibit 219 at pp. 2 and 4.) Yet in 1994 only 2% and 11%, respectively, of Edison's pre-1991 and post-1991 retirees were

73 Although Foster Higgins' results at the subregional level should be tempered by the possible impact of sampling bias, they are consistent with Edison witness Bertko's above-cited conclusion that "a great bulk of [California's] population is now in... HMO's." Other record evidence indicates that about half of privately-insured California residents were in HMO's in 1994. (Exhibit 228.)

enrolled in HMO's. (Exhibit 233.) The corresponding percentages for 1995 are much higher, 26% and 32%, respectively. (e.g., Edison's Point-of-Service plan commenced on January 1, 1995.)

Edison's suggestion that in prior years it gradually accrued cost savings on the order of what other firms realized in a "one-time" savings in 1994, is independently impeached by the data used to rebut DRA's challenge to its test year 1995 request as discussed in Section 14.1.2 above: the very close match between the health insurance subindices of ECIBPNS and the escalation rate of Edison's costs. (Exhibit 201 at pp. 9, 16-17.) In order to have absorbed the "one-time" savings over the period of its cost containment program (which began in 1989), Edison's annual rate of cost escalation would have had to run about 2% lower than the national rate (extrapolating the ECIBPNS health subindices through 1994).

Conversely, despite the magnitude of its 1994-1995 movement toward HMO's, Edison's request does not reflect "one-time" dividends comparable even to what other western firms enjoyed in 1993-1994, as reported by Foster Higgins. Edison's overall 1994-1995 cost increase -- 6.90% -- is well above inflation, while the West as a whole experienced only a 2.0% increase in 1993-1994, considerably below inflation. (In contrast, Edison's recorded costs rose 11.97% from 1993 to 1994.) Thus Edison has not of late managed its health care costs as successfully as the typical western firm in the Foster Higgins survey. (Exhibits 218, 220.)

The "one-time" savings from the shift toward lower cost health plan types is an important but not the exclusive factor in arresting health care inflation. As the Foster Higgins Press Release states, employers in 1994 "seized the initiative to hold down cost through use of managed care plans and other cost management techniques." (Exhibit 219, emphasis added.)

The record establishes that, in California, a very prominent example of such a cost-management technique has been the

deployment of aggressive purchasing strategies, either via a pooling arrangement or singly through enterprising price-shopping. The achievements of pooled purchasing programs such as those executed by CALPERS and the Pacific Business Group are developments of tremendous significance. In addition, the City of Sacramento, with only 4,000 employees (about one-fourth Edison's size), realized premium rollbacks up to 22% for 1994; the University of California achieved 8% and up to 10% reductions for 1994 and 1995, respectively. (Exhibit 228.)

The record shows that Edison failed to actively pursue lower-cost health care contracts during a period when others did so with demonstrable success. During evidentiary hearings in 1994, Edison cross-examined DRA with respect to the latter's argument that CALPERS' success in reducing its health care premiums was an example for Edison to emulate. Responding to Edison's query whether he agreed that since Edison was considerably smaller than CALPERS, its bargaining power should be correspondingly weaker, DRA's witness countered that Edison's smaller size was "not really relevant. (T)here is nothing to prevent Edison from contacting other employers or working together with other employee groups or industry groups to engage in the same kind of group purchasing." (R.T. Vol. 37, pp. 4192-4193.) Shortly after this hearing-room exchange, Edison's health care rebuttal testimony opined that since CALPERS' count of covered lives was approximately seventeen times greater than Edison's, Edison was incapable of exerting comparable market leverage. Edison, however, did not address DRA's pooled purchasing concept. (Exhibit 201 at p. 34.) Approximately four months after Edison filed this rebuttal, it became generally known that the Bay Area Business Group (as it was then called) had aggregated the collective market muscle of nearly a dozen firms to achieve a very substantial reduction (averaging 9.2%) over a large array of HMO health plans for 1995. (Exhibit 228.) About a month later, in November 1994, Edison itself joined this health-care

purchasing pool, newly renamed the Pacific Business Group on Health. (Exhibit 231.)

We conclude that for ratemaking purposes we should adopt health care trend rates which compensate ratepayers for Edison's foregone opportunity to take advantage of the emerging buyers' market, which Edison could have done by reacting sooner and, for example, using its regional leadership concept to combine its purchasing power with other businesses. The record is too spotty to determine whether such pooled purchasing has yet consistently penetrated beyond the HMO market, so we proceed conservatively, reasoning that Edison should at least have begun to realize HMO cost savings on the same order as CALPERS by 1994, and an average of the savings achieved by CALPERS and the Bay Area Business Group for 1995. (These considerations render moot Edison's factual dispute with TURN regarding Edison's actual HMO rate escalation for 1993 - 1995.)

Today's decision diverges from the Proposed Decision primarily in our determination that Edison's uniform 9% HMO trend rate for 1993-1995 is adopted as reasonable for 1993, since most of the evidence of downward market pressure concerns 1994 and after. Based on the 1994 HMO rate decreases achieved by CALPERS as well as other single entities, we believe it reasonable that Edison should at least have held the line on its 1994 HMO premiums, and we accordingly adopt a 0% trend for that year. Because the record closed prior to announcement of CALPERS' 1995 HMO decrease, we borrow the previous year's result (-1.7%) to average with the 9.2%

savings achieved by the Bay Area Business Group for 1995 to arrive at a -5.5% trend for that year.[74]

With respect to the appropriate 1993-1995 trend rates for non-HMO insurance categories, we are persuaded by TURN's argument that more recent trend rates from a nearby region should carry more weight than older, national rates. Edison has not shown how systematic differences in plan structure and demographics should force the cost of every one of its health plan types to somehow escalate faster than the corresponding plan type of a neighboring utility. TURN's common-sense approach is reasonable and we adopt it. We also adopt TURN's PrimeCare correction; Edison did not demonstrate how it double counts already adjusted data.[75]

Finally, with respect to administrative costs, we agree that Edison's 1992-1995 cost increase is not necessarily a one-time change given its ongoing activities in health care plan development and management, and therefore adopt Edison's proposed administrative budget.

<u>14.3.3 Adopted Health Care Budget</u>

To derive Edison's test year 1995 health care expense level, we have revised TURN's calculations, substituting our HMO trends and Edison's administrative budget as appropriate. We have followed TURN's method of detrending Edison's test year 1995

74 Although we do not rely on the following point, we note that our determination is validated by the evidentiary record in the current general rate case for Pacific Gas and Electric Company. In March 1995, PG&E made several downward adjustments to its projected health care budget. Prominent among these changes was a reduction in its 1995 HMO trend rate from plus 3% to minus 9.8% (A.94-12-005, Exhibits 19 and 96.) (TURN presented PG&E's original HMO trend rates in Exhibit 760 in this case, but did not update them.)

75 We corrected two errors in TURN's PrimeCare calculation which nearly are mutually cancelling.

estimates back to 1992, then applying the appropriate trends to recalculate 1995 costs, as shown in Exhibit 223.[74] Since the HMO trend also impacts Edison's Point-of-Service program (because of the 50/50 weighting of fee-for-service and HMO trends used to derive Edison's Point-of-Service costs), our adopted budget is lower than the settlement by $6.237 million and $7.338 million for HMO's and Point-of-Service, respectively, $1.406 million lower for PrimeCare, and very slightly lower ($0.230 million in aggregate) for dental, vision, and corporate medical programs. The overall budget, as shown in Appendix D, is thus $15.212 million lower than the settlement, resulting in an adopted health care budget of $140.487 million compared with $155.699 million for the settlement.

Our adopted health care budget of $140.487 million represents an annualized increase of 4.9% from Edison's 1992 recorded costs ($121.590 million), somewhat above annual inflation (2.8%) for the same period. As with TURN's proposal, our adopted health care budget assumes the same health plan structure and enrollment as Edison's, and differs only with respect to the trend rates.

<u>14.4 Nonhealth Care Costs</u>

<u>14.4.1 Miscellaneous Employee Benefits Expenses</u>

At evidentiary hearings before the settlement, DRA recommended the Commission not authorize about $1.2 million in miscellaneous employee benefits expenses (e.g., Edison Employees Club, employee recognition and service awards, American Legion, Diamond Club) which it believed constitute an undue levy on captive ratepayers. DRA reasoned that "meeting expenses" are analogous to club dues, which the Commission does not allow ratepayers to fund. DRA also reasoned that service and recognition awards properly fall within the category of "social activities" which are inappropriate for ratepayers to fund.

Edison stated that since these expenses are neither dues, donations, nor charitable contributions, they are not excluded

under prior Commission decisions. Edison asserted that these expenses provide ratepayer benefits and thus do not constitute an undue levy on ratepayers.

In the settlement, Edison assented to removal of the "miscellaneous employee benefits expenses," as "they might not provide a ratepayer benefit." (Settlement Joint Comparison Exhibit at p. 126.) Our review of the record persuades us that these expenses have a predominantly social character. We approve DRA's requested reduction of miscellaneous employee benefits.

14.4.2 Employee Discount Reimbursement

In Phase 2 of this proceeding, DRA has proposed abolishing the 25% domestic rate discount for Edison employees. While DRA's proposal intends to be revenue neutral (by simply reallocating the subsidy back to other domestic ratepayers), it is not in fact entirely so. Edison's Phase 1 request included an additional $0.7 million to reimburse those employees (and retirees) who, because they live outside Edison's service territory, would not otherwise receive the discount.[76] It would be inequitable to adopt the reimbursement expenses just for this small number of employees in advance of our Phase 2 decision on the merits of DRA's proposal, which is meant to eliminate the discount for everyone. We have accordingly removed the reimbursement funding from the ALBRR pending resolution of this issue in Phase 2. These funds may be restored by the Advice Letter process in the event our Phase 2 decision retains the employee discount.

In Section 19, we establish the test year revenue requirement for Edison's total compensation. This amount does not reflect any domestic rate discounts to Edison employees that live within Edison's service territory, since these discounts are a

76 DRA's Phase 1 testimony did not contest this funding, and it is included in the settlement revenue requirement.

noncash benefit realized through rate design. Our determinations in Section 19 will apply irrespective of whether our Phase 2 decision eliminates such discounts.

14.4.3 Account 926 Capitalization Error

At the settlement hearings, the ALJ queried Edison regarding an arithmetic error in the calculation of the settlement amounts in subaccount 926.9, relating to P&B capitalization. Edison's witness, Kubasek, explained that correcting this error would lower the revenue requirement by about $1.5 million. However, Kubasek also indicated that in other areas Edison will experience a revenue requirement increase from that of the settlement. For example, Kubasek states that the Northridge earthquake in 1994 increased Edison's property insurance costs, yet Edison is not seeking an upward adjustment of the settlement. (See R.T. Vol. 58 at pp. 6640-6641.)

Edison did not quantify the amount of the increase in the property insurance premium. However, we believe it equitable to offset the $1.5 million capitalization error against the increase in property insurance, and therefore do not reduce Account 926 further for this item.

15. Research, Development & Demonstration (RD&D)

In its original application, Edison requested $53.756 million for RD&D for test year 1995. DRA recommended $31.846 million. In the settlement, Edison and DRA agreed to $25.387 million for RD&D and $458,000 for RD&D O&M expenditures. We adopt a total funding level of $27.465 million for RD&D and $458,000 for RD&D O&M expenditures. This level is slightly higher than that

recommended by the settling parties to conform to our prior decisions and determinations based on the record.[77]

Edison's RD&D expenditure portfolio consists of five programs. Within each program are sub-programs composed of project areas. Those project areas contain identifiable projects. Edison's application provided funding requests, descriptions, goals, objectives and potential benefits at the program, sub-program, project area and project level. DRA utilized this level of detail in its review, analysis, and as the basis for its original recommendations.

The settling parties' additional testimony did not provide the type of detail provided in the original testimony. However, in response to an ALJ ruling, Edison and DRA provided a breakdown of the settlement funding request at the sub-program and project area level. The settling parties state that the original descriptions, justifications, goals and objectives have not changed for any of the project areas proposed in the settlement. Rather, the settling parties have achieved reduced funding levels by extending project area schedules or elements, and by eliminating generation-related project areas. As a result, the impact of the reduced funding is to spread out the projects over a somewhat longer period of time, and probably prevent Edison from funding new research projects that may have been undertaken.

The CEC opposed the settlement, and generally recommended that we approve Edison's original RD&D request. The CEC is particularly concerned with the reductions in what it terms "public

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77 Besides Edison and DRA, the following parties participated in the evidentiary hearings or briefing on Edison's original application with respect to RD&D: APS; Ascension; Bechtel; DGS; CEC; CSEI; NRDC; SDG&E; SMUD; SEIA; SCAQMD; SCAG; UCS; DOE; UC; and UPVG. Besides Edison and DRA, CEC and NRDC participated in the hearings or briefing on the settlement phase with respect to RD&D.

goods" research, principally in the area of advanced generation. However, in an effort to mitigate the harm it believes the settlement would impose and to find common ground with both Edison and DRA, the CEC offered to withdraw its opposition if the settling parties would reflect the following changes in the settlement agreement: (1) a slightly different allocation of the project area funds (the settlement's overall funding level would remain the same) and (2) the adoption of some policy language.[78]

Edison stated that although the amounts suggested in the CEC's compromise are in accord with its current planned RD&D spending, it could not agree because it believes that the project area level allocation is below the level at which the Commission authorizes RD&D funding. Edison also would not change the settlement to adopt the CEC's proposed policy statement.

Although the amount we authorize for RD&D in this rate case is a substantial reduction from that originally requested by Edison, we believe that it is an appropriate level of funding based on our discussion of each project area below. We are in the

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78 The CEC's proposed policy language is as follows:

> "Restructuring and increasing competition in the electric industry will impact utility RD&D in California. Edison, DRA and the CEC recognize that a substantial reduction in ratepayer-funded investor-owned utility RD&D for non transmission and distribution (T&D) projects may occur based on restructuring and increasing competition in the electric services industry. Due to this expected change in RD&D, Edison, DRA, and the CEC support the creation of a broadly funded RD&D program for public goods. In order to maintain a level playing field, funding of this new RD&D program should be fair and equitable to all customers and providers of electricity in California. Edison, DRA and the CEC have agreed to a RD&D transition period in this general rate case."

process of developing policies governing the restructuring of California's electric industry (R.94-04-031/I.94-04-032). Our proposed changes are, in part, in response to increasing competition in the generation sector. Thus, currently there exists some uncertainty regarding the role of the utility and RD&D (i.e., what types of RD&D activities utilities or competitors will be pursuing, how RD&D will be funded, etc.). The level we authorize today reflects this uncertainty.

For example, we have approved reductions to certain generation-related research as generally proposed by the settling parties because we agree that allowing Edison to use ratepayer funds to perform this research at this time could be viewed as anticompetitive in a future that does not view generation as a continuing monopoly function of the utility, or because it might not provide benefits to Edison's particular ratepayers[79] if Edison does not continue in the new generation business. However, we will continue to fund certain projects within the Advanced Generation Program through December 31, 1997. Funding is authorized for these projects in order to maintain some continuity for these programs in the face of uncertainty surrounding restructuring of California's electric industry. We believe research in this area provides the potential for long-term environmental and resource diversity benefits for ratepayers that outweigh potential anticompetitive concerns associated with ratepayer funding in this area at this time. However, we do not address funding for incremental generation research after December 31, 1997 because this issue goes beyond the current rate case cycle and is of broader policy concern. Broader policy concerns about the future funding of RD&D

79 What we refer to here are benefits which Edison's specific ratepayers may glean from the RD&D research, as opposed to benefits which all users of electricity might glean from the research.

should be addressed in our electric industry restructure proceeding or other appropriate generic proceeding.

No party to the settlement proceedings contends that the RD&D portion is inconsistent with the guidelines set forth in PU Code § 740.1. The CEC argues that the RD&D funding levels proposed in the settlement are not balanced between short-, mid-, and long-term needs as set forth in the RD&D objectives in Appendix C of D.90-09-045, 37 CPUC2d 390, 397-398. However, we believe the funding level we approve, which is not as focused on long-term needs, is appropriate for the three-year general rate case cycle, which is a period of transition, given the uncertainty discussed above. Again, we note that broader concerns about the future funding of RD&D are not determined here.

We also disagree with Edison's statement regarding the manner in which we authorize RD&D funding. Prior to this general rate case, we have not adopted an RD&D funding range for Edison. Consequently, we do not merely authorize funding at the program level but rather, we authorize funding of specific projects or project areas as appropriate. (See, e.g., D.91-12-076, 42 CPUC2d at 707.) Edison has the flexibility to deviate from authorized levels according to existing program level fund-shifting guidelines. Subsequent modifications to its RD&D portfolio is a separate issue from the manner in which we initially authorize funds.

Since Edison and DRA maintain that they have not modified descriptions, justifications, goals or objectives of the project areas being proposed for funding in the settlement from Edison's original position, we will decide the appropriate project area funding levels based on Edison's original request, the parties' initial positions, the settlement, and the intervenors' responses to the settlement. Table 15.1 provides the parties' positions and our adopted amounts for each project area.

TABLE 15.1

TEST YEAR 1995 RD&D
($ IN THOUSANDS)

Line No.	Program/Sub-Program/ Project Area	Edison Request (1992 $)	DRA Position (1992 $)	Settlement (1992 $)	Adopted (1992 $)
1	**Advanced Generation Program**	$5,340	$91	$1,189	$3,416
2	*Solar*				
3	Solar II	$917	$0	$274	$274
4	Advanced Solar Thermal	$230	$0	$0	$230
5	Photovoltaic Development Off-Grid	$91	$0	$0	$0
6	Photovoltaic Development On-Grid	$457	$0	$458	$457
7	*Fuel Cells*				
8	Distributed Fuel Cell	$641	$0	$366	$366
9	National Fuel Cell Research Center	$1,639	$0	$0	$1,639
10	*Wind Energy*	$275	$0	$0	$275
11	*Geothermal*	$183	$0	$0	$183
12	*Storage*	$91	$91	$91	$91
13	*Waste-to-Energy*	$916	$0	$0	$0
14	**Asset Utilization Program**	$11,602	$6,634	$4,321	$4,318
15	*Generation Improvement*				
16	Heat Rate Improvement	$871	$100	$0	$0
17	Diagnostic Monitoring & Controls	$459	$0	$0	$0
18	Improved Maintenance and Operations	$1,103	$0	$0	$0
19	Electrical Efficiency Improvement	$229	$229	$0	$0
20	Advanced Gas Turbines	$184	$0	$0	$0
21	Advanced Computing Technologies	$91	$45	$46	$46
22	*Emission Control*				
23	SCR/SNCR Optimization	$110	$0	$0	$0
24	Toxic Air Emissions	$366	$0	$0	$0
25	Advanced Combustion Techniques	$0	$0	$0	$0
26	Combustion Systems Efficiency Improvement	$633	$633	$0	$0
27	*T/S Control, Monitoring, & Diagnostics*				
28	Protective Devices	$631	$457	$275	$275
29	Transmission System Stability & Control	$558	$485	$458	$458
30	*Transmission 2010*				
31	Composite Transmission Towers	$282	$282	$275	$282
32	Advanced Transmission Control Systems	$485	$485	$457	$457
33	Underground Transmission	$272	$182	$91	$182
34	Advanced Transmission Concepts	$531	$0	$183	$73
35	*Distribution*				
36	Distribution Automation	$732	$732	$366	$366
37	Advanced Metering	$457	$0	$201	$201
38	Underground Distribution Cable	$183	$183	$183	$183
39	Power Quality	$292	$292	$228	$228
40	*Communication & Control*				
41	Substation Communication & Control	$2,200	$1,879	$1,191	$1,191
42	Distributed Communication & Control	$183	$0	$0	$0
43	Adv. Mobile Communication & Information	$366	$366	$92	$92
44	Future Edison Communication Architecture	$284	$284	$275	$284

TABLE 15.1
TEST YEAR 1995 RD&D
($ IN THOUSANDS)

Line No.	Program/Sub-Program/ Project Area	Edison Request (1992 $)	DRA Position (1992 $)	Settlement (1992 $)	Adopted (1992 $)
45	**Customer Systems Program**	$5,826	$1,399	$2,729	$1,684
46	*Transportation Research*				
47	Low Emission Vehicles (1)				
48	Advanced Transit	$530	$0	$275	$276
49	*Customer Energy Technologies*				
50	Industrial/Environmental	$362	$181	$164	$164
51	Advanced Commercial	$1,384	$692	$687	$687
52	Advanced Residential	$1,052	$526	$458	$458
53	*Customer Air Quality Improvement*				
54	NOx Reduction	$1,457	$0	$504	$0
55	ROC Reduction	$390	$0	$276	$0
56	Toxic Air & Halogen Control	$367	$0	$183	$0
57	Conservation-Based Environmental Compliance	$284	$0	$183	$0
58	**Environment, Health, & Safety Program**	$7,045	$4,475	$1,740	$1,740
59	*Environmental Research*				
60	Air/Water/Land Quality	$1,930	$955	$458	[illegible]
61	Natural Habitat Conservation	$1,475	$950	$366	$366
62	Community Environmental Quality	$2,140	$1,420	$550	$550
63	*Occupational Health & Injury Prevention*				
64	Work Health Exposures	$350	$0	$0	$0
65	Ergonomics	$250	$250	$92	$92
66	*Electric & Magnetic Fields*	$900	$900	$274	$274
67	**Management, Support, & Memberships**	$20,477	$19,247	$15,408	$16,408
68	*Research Management & Support*				
69	Management	$1,000	$814	$546	$546
70	Support	$1,597	$1,217	$546	$546
71	Division Operations	$1,147	$874	$505	$505
72	*Regulation, Contracts, & Valuation*				
73	Regulation	$823	$627	$183	$183
74	Financial Analysis & Valuation	$549	$419	$182	$182
75	Contract Management	$276	$210	$137	$137
76	*Industry Memberships*				
77	EPRI	$14,640	$14,640	$13,309	$13,309
78	CIEE	$500	$500	$0	$1,000
79	WEST Associates	$46	$46	$0	$0
80	**Related O&M Expense**	$0	$0	$458	$458
81	**TOTAL Research Expense Program**	$50,190	$31,846	$25,845	$27,9[illegible]

(1) Edison's LEV request is being addressed in I.91-10-029/R.91-10-028.

15.1 Advanced Generation Program

Edison originally requested $5.340 million to develop and demonstrate what it believed to be cost-effective, environmentally sensitive, advanced generation technologies to meet future energy requirements. The CEC supported Edison's application request in full for this program. DRA recommended a program funding level of $91,000. DRA did not oppose Edison's request for its Advanced Storage project area. Since this request was uncontested in Edison's original application, and the settling parties agreed to it, we adopt $91,000 for this project area.

15.1.1 Incremental Generation Project Areas

Edison originally requested $917,000 for Solar II, $230,000 for Advanced Solar Thermal, $1.539 million for the National Fuel Cell Center, $275,000 for Advanced Wind Turbines and $183,000 for Integrated Geothermal Cycles. DRA grouped these funding requests into a single category called "incremental generation."[80] DRA recommended zero funding for these project areas because Edison's ratepayers should not have to fund incremental generation research in an increasingly competitive generation marketplace, since this would give Edison an unfair advantage over its competitors.

The CEC and the UCS supported Edison's request. They argued that the Commission has not yet determined what will be justifiable utility RD&D investment under the conditions of the new competitive industry restructuring. Therefore, the particulars of the restructuring and the mechanics of the transition should be developed prior to any termination of funding for research of advanced technologies. SDG&E similarly urged us to consider

80 DRA used the term "incremental generation" to refer to central-station generation additions that are typically 100 MW or greater in size and interconnected to the utility's transmission or sub-transmission system.

implementation issues if shareholder funding is to replace ratepayer funding. The CEC and DOE requested us to preserve the integrity of existing cost-shared RD&D agreements between parties which will enable utilities to complete RD&D efforts in progress. SCAQMD, Bechtel, and SMUD supported all or portions of Edison's original request because of the benefits to California's energy, economic, and environmental future.

The settling parties agreed to a funding level of $274,000 for Solar II, and agreed to not allocate any funding to the remaining project areas. They also agreed that ratepayer funding of Solar II research will be phased out completely by December, 1997.

As stated above, we believe research in this area provides the potential for long-term environmental and resource diversity benefits for ratepayers that outweigh potential anticompetitive concerns associated with ratepayer funding in this area at this time. We adopt the $274,000 settlement recommendation for Solar II. Consistent with Edison's original request, we adopt $230,000 for Advanced Solar Thermal, $1.539 million for the National Fuel Cell Center, $275,000 for Advanced Wind Turbines, and $183,000 for Integrated Geothermal Cycles.

15.1.2. Photovoltaic (PV) Development Off-Grid Project Area

Originally, Edison requested $91,000 to build upon its prior research efforts on off-grid PV systems. Edison stated that this research would emphasize development of new and improved techniques for reducing the installation, operation and maintenance costs of remote systems. DRA recommended zero funding for this research since off-grid PVs are already commercial and have been viably demonstrated in the competitive marketplace. An intervenor, on behalf of Independent Power Providers (IPP), which is a trade organization of over 45 PV companies, stated that it also believed allowing the utility to use ratepayer money to fund Edison's off-grid research would promote unfair competition. The settling parties agreed to cancel this project area.

In May 1994, we gave final approval for Edison to implement a three-year pilot project to test the feasibility of offering PV service as an alternative energy source to customers in remote locations where a line extension is not economical. We do not believe that additional research of off-grid PVs is warranted at this time and do not authorize funding for this project area.

15.1.3. Photovoltaic Development On-Grid Project Area

Edison originally requested $457,000 to examine techniques to reduce total costs through: (1) advanced materials (such as thin film materials); (2) cost-effective applications (such as architectural PV); and (3) reducing the balance of system costs through improved installation techniques, higher efficiency lower-cost inverters and advanced communications.

DRA opposed ratepayer funding of grid-connected PV research, since it may give Edison an unfair advantage in early entry into the on-grid PV market and could blunt competitive pressure to restrain rates.

Ascension did not believe that the research would give Edison a competitive advantage but rather would enable the development of better ways to integrate PV power into power

transmission and distribution operations. UPVG believed that utility funding of PV research is necessary to achieve commercial success. No matter what Edison's later role in generation activities may be, UPVG believed that the benefits of the research would be jobs, cleaner air, lower-cost PV systems, and early access to PV technology by all consumers and support contractors. CSBI and APS also supported Edison's original request. CSBI asserted that the development and deployment of PV technologies will serve to increase the reliability and efficiency of Edison's utility service; displace inherently less safe generating technologies, improve their services from an environmental and social responsibility perspective and reduce rates.

The settlement did not modify the objectives or planned funding for this project area. However, DRA and Edison did agree that funding for On-Grid PV research should not exceed 12 distribution circuits through 1997. In order to enable funding of the Advanced Gas Turbine Project discussed above, the CEC recommended that this project area be reduced by $92,000.

We believe the potential long term social benefits that research in this area can provide outweigh anticompetitive concerns associated with ratepayer funding at this time. We approve funding at Edison's original requested amount of $457,000. We also adopt the DRA and Edison agreement that On-Grid PV research should not exceed 12 distribution circuits through 1997.

<u>15.1.4 Distributed Fuel Cell Project Area</u>

Edison originally requested $641,000 to fund its distributed fuel cell project area. Edison stated that ratepayer

benefits from distributed fuel cell research include deferral of conventional central plant generation or delaying of a substation upgrade. DRA opposed this research because it is intended to replace or delay incremental central plant generation.

In rebuttal, Edison pointed out that the distributed fuel cells have many beneficial uses beyond replacing or delaying central plant generation. It contended that fuel cells enable the deferral of transmission, substation and distribution system upgrades. In addition, it described other benefits such as frequency and voltage stabilization capability, improved system reliability, and lower financial risk.

In the settlement, DRA and Edison agreed to a revised funding level of $366,000 to quantify and evaluate the costs and benefits of a distributed generation technology's impact on deferring transmission and distribution line expenditures. Both parties further agreed that ratepayer funding of central station fuel cell research will be phased out completely by December 1997.

The additional potential benefits cited by Edison convince us to allow partial funding. We believe that fuel cells used in distributed applications described by Edison provide ratepayer benefits by reducing system operating costs and have associated environmental benefits. We approve funding at the settlement's recommended level. However, as stated above, we do not address the curtailment of all funding in this area after December 1997 as this issue is beyond the scope of the current rate case cycle and is of broader policy concern.

<u>15.1.5 Advanced Integrated Recycling (AIR) Project Area</u>

Edison originally requested $916,000 to pursue this project, which involves the use of an advanced gasification technology to provide a renewable source of power plant fuel and an environmentally beneficial alternative for solid waste disposal. DRA recommended zero funding for this project because it asserted

that it was high risk, no cofunding was provided, and the gas produced is not needed.

The settling parties agreed that SCEcorp should be allowed to fund research and commercialization of the AIR project, provided that it reimburse ratepayers $100,000 for this project if it decides to pursue the research. We are not convinced that the project should be funded with ratepayer monies and therefore we adopt the settlement recommendation.

15.2 Asset Utilization Program

Edison originally requested $11.592 million to fund its Asset Utilization Program, which was aimed at reducing operating costs and improving productivity through advancing state-of-the-art technologies in generation, transmission, distribution and control systems. Edison's request was composed of six sub-programs. DRA recommended a program funding level of $6.634 million.

In the settlement, DRA and Edison agreed to a funding level of $4.431 million. They stated that this funding level is intended to balance the need to take immediate steps to lower customers' rates and the longer-term goal of researching advanced technologies to reduce the cost of operating and maintaining Edison's operating system in the future, while improving the overall quality of service. In particular, the settlement reduces the funds that had been proposed for generation-related improvements to levels consistent with short-term improvements.

15.2.1 Generation Improvement Sub-Program

Edison originally requested $2.937 million for this sub-program to research and demonstrate new technologies to improve power plant efficiencies and reduce the operating costs of existing power plant systems.

DRA recommended a funding level of $374,000. DRA alleged that Edison had no clear, directed plan for its Heat Rate Improvement research. It recommended denying funding for the Diagnostic Monitoring project area because Edison had not justified

the need for additional control system research. DRA recommended that all research associated with improving the O&M of nuclear units be denied as a result of its position with respect to the cost effectiveness of operating SONGS. Consistent with its position regarding incremental generation research, DRA recommended no funding for the Advanced Gas Turbine Project Area. DRA recommended cutting the funding level in half for the Advanced Computing Systems (ACS) project area because Edison could actively participate in the research being conducted by others.

SDG&E addressed DRA's recommendation and Edison's possible involvement in its ACS research. SDG&E considered its project proprietary and rejected third-party participation.

In the settlement, Edison and DRA agreed to cancel all project areas except the ACS project area, which they agreed to fund at DRA's recommended level. They eliminated the project areas because they were generation-related.

DRA's initial arguments and those offered by the settling parties convince us to not authorize funding for the Heat Rate Improvement, Diagnostic Monitoring and Control, Improved O&M, Electrical Efficiency Improvements, and Advanced Gas Turbines project areas. We agree with and will adopt DRA's advanced computing systems project area funding recommendations.

15.2.2 Emission Control Sub-Program

Edison originally requested $1.559 million to research and demonstrate new technologies and processes to reduce critical pollutants from Edison's fossil fuel generation, and assess the economic impact of implementing these new technologies.

DRA recommended $633,000. This reduced level was the result of DRA's recommendation to allow full funding for the Combustion Systems Efficiency project area and deny funding for three of Edison's other proposed project areas. DRA alleged that Edison's Selective Catalytic Reduction/Selective Non-Catalytic Reduction Optimization Project Area and its Advanced Combustion

Project Area lacked economic justification and that its Toxic Air Emissions Project Area was duplicative of prior research. In addition, DRA believed that it was unreasonable to conduct research addressing regulations that have not yet been implemented. In its opening brief, Edison stipulated that it would withdraw its request for the Advanced Combustion Project Area because the participants could not agree to contractual terms for royalties, licensing fees and other key issues.

In the settlement, Edison and DRA agreed to cancel all project areas because they are generation-related. We agree with the settlement's recommendation based on DRA's initial concerns and in light of our previous discussion on generation-related research.

15.2.3 T/S Control, Monitoring & Diagnostics Sub-Program

Edison originally requested $1.189 million to identify and develop near-term advanced technologies to increase transmission system efficiency, reliability and capacity, and to reduce O&M costs. This request was composed of $631,000 for the Protective Devices Project Area and $558,000 for the Transmission Stability & Control Project Area.

DRA recommended $942,000 based on its claim that a project within the Protective Devices Project Area should be developed by the market instead of Edison's ratepayers and that the Transmission Stability & Control Project Area contained projects which lacked economic justification.

In the settlement, Edison and DRA agreed to extend the project area schedules for both. The revised project area funding levels are $275,000 and $458,000 for Protective Devices and T/S Stability & Control, respectively.

We believe that Edison's projects within these project areas are designed to increase operating efficiency and system versatility. We also believe that the schedules may be extended without jeopardizing the projects and therefore adopt the settlement's recommended amounts.

15.2.4. Transmission 2010 Sub-Program

Edison originally requested $1.570 million to research and develop the power delivery system it anticipated needing 15 years from now. This included research into new compact transmission towers and underground systems and advanced energy handling components to throttle and divert power flows in an increasingly efficient and better utilized transmission network. Edison's sub-program request was composed of $282,000, $485,000, $272,000 and $531,000 for the Composite Transmission Towers, the Advanced Transmission Control, the Underground Transmission, and the Advanced Transmission Concepts project areas, respectively.

DRA agreed with Edison's request for the Composite Transmission Towers and the Advanced Transmission Control Systems project areas, recommended a reduced funding level of $182,000 for the Underground Transmission project area, and recommended no funding for the Advanced Transmission Concepts project area. DRA claimed that two projects totalling $90,000 within the Underground Transmission Project Concepts Area and all three projects within the Advanced Transmission Project Area appeared to be highly conceptual, speculative, or of high risk, and best left to the Electric Power Research Institute (EPRI).

In the settlement, Edison and DRA agreed to fully fund the Composite Transmission Towers project area and extend the schedules for the three remaining project areas. The revised funding levels are $457,000, $91,000, and $183,000 for the Advanced Transmission Control Systems, the Underground Transmission, and the Advanced Transmission Concepts project areas, respectively.

We, along with DRA, find Edison's original requests of $282,000 for the Composite Transmission Towers and $485,000 for the Advanced Transmission Control Systems project areas reasonable. However, we will authorize a lower funding level of $457,000 for the Advanced Transmission Control Systems project area based on the

schedule extension proposed in the settlement. The Composite Transmission Towers project area should remain funded at $282,000.

We authorize $182,000 for the Underground Transmission project area and $73,000 for the Advanced Transmission Concepts project area. We make this determination based on Edison's reported probability of success ranges for projects proposed within these project areas, as well as the settlement's schedule extension for the Underground Transmission project area.[81]

15.2.5 Distribution Sub-Program

Edison originally requested $1.664 million to research and demonstrate advanced automated technologies to increase the efficiency and reliability of its distribution circuits and substations. DRA recommended a $1.207 million funding level for this sub-program. DRA objected only to the Advanced Metering project area. DRA believed that no funding should be allowed for this project area because Edison had already spent over 8 years and $31.6 million trying, with no success, to develop a cost-effective communications technology and advanced metering device.

In the settlement, Edison and DRA agreed to reduce the Advanced Metering project area funding by $201,000 by extending the schedule. They also agreed to reduced funding for two other project areas as the result of schedule extensions. We believe

81 Edison supported its requests for the Dynamic Line Ratings project, the Distributed Cable Puller project, and the Wireless Power Transmission projects with probability of success ranges of 50% to 75%, 30% to 50%, and 30% to 50%, respectively. We find these ranges acceptable. The probability of success ranges for the Fourier Transformer Power Transmission System and the Advanced Electrical Systems projects, however, had ranges less than 30%. We think these are too low. We do not normally deny funding on the sole basis of low probabilities of success. However, low probabilities of success ranges, combined with the fact that EPRI is not (and probably will not be) providing funding, persuaded us to deny funding for these projects.

Edison's original request for these project areas has merit, as do the schedule extensions proposed in the settlement. Accordingly, we approve the settlement project areas and amounts.

15.2.6 Communication & Control Sub-Program

Edison originally requested $31.033 million for this sub-program to study ways to reduce O&M and improve customer service. The project areas within this sub-program are Substation Communication & Control, Distributed Communication & Control, Advanced Mobile Communication & Information, and Future Edison Communication Architecture.

DRA's initial review indicated that certain projects within the Substation Communication & Control and the Distributed Communication & Control project areas were similar to those requested in other research areas and did not justify separate funding. Accordingly, DRA recommended a reduced funding level for the Substation Communication & Control project area and no funding for the Distributed Communication & Control project area. DRA did not contest the Advanced Mobile Communication & Information or the Future Edison Communication Architecture project areas.

In the settlement, Edison and DRA agreed to cancel the Distributed Communication & Control project area, to fund the Future Edison Communication Architecture project area as proposed in Edison's original request, and to extend the schedules for the Substation Communication & Control and the Advanced Mobile Communication & Information project areas.

We agree with DRA's initial argument that Edison did not adequately justify its project requests within the Substation Communication & Control and the Distributed Communication & Control project areas. We believe that the Substation Communication & Control project area funding could be lowered further in order to achieve the schedule extension proposed in the settlement. We believe the proposed funding for the Advanced Mobile Communication & Information project area is justified based on the level which

provides for a schedule extension. We will also approve Edison's original request for the Future Edison Communication Architecture.

15.3 Customer Systems Program

Edison originally requested $5.826 million to develop and demonstrate new technologies or new applications of existing technologies to address the concerns primarily of residential and business customers. DRA recommended a program funding level of $1.399 million.

The settling parties agreed to a level of $2.729 million. All project area reductions within this program, except for the Mass Transit project area reduction, were the result of proposed schedule extensions. The parties agreed to fund the Mass Transit project area based, in part, on DRA's initial recommendation.

15.3.1 Transportation Research Sub-Program

Edison originally requested $530,000 to participate with local, state or federal government entities, as well as the private sector, to investigate the feasibility of high-speed rail systems (for commuters) and heavy rail systems (for commuters and commercial transport) in southern California and their potential impact on the utility grid.

DRA recommended zero funding. DRA argued that a good deal of information should already be available, and ratepayer funds should not be used to investigate the feasibility of any technology that is not, or has no prospect of being, a utility service.

The settling parties agreed to a funding level of $275,000. Edison agreed to limit its research to determining (1) the impact of high-speed and heavy rail systems on the Edison grid and (2) Edison's system preparedness for the rail load.

High-speed electric mass transit and heavy rail systems are currently being developed in Edison's service territory. While we do not believe Edison should be investigating the feasibility of such systems with ratepayer funds, we do think it is Edison's

responsibility to ensure that its system can serve the potentially large loads associated with the rail systems. We therefore approve the settlement's recommendation.

15.3.2 Customer Energy Technologies Sub-Program

Edison originally requested $2.798 million to identify, develop, and demonstrate new technologies and new applications of existing technologies that address customer needs and conserve electric energy. DRA recommended $1.399 million due to Edison's past low success rate of advancing similar projects to the marketplace. Edison argued that many of the technologies have not yet advanced to the marketplace because they are still undergoing research and development. Edison testified that it expects these technologies to be successful in the future. Edison stated that it carefully evaluates each project's potential for success, including any limitations on commercialization in the marketplace.

In the settlement, Edison and DRA agreed to extend all three project area schedules. These schedule extensions reduce Edison's funding request to $1.309 million.

We do not believe that DRA successfully challenged the merits, the forecasted benefits, or the need for any of the individual proposed research projects in this sub-program. However, we do believe the project schedules may be extended without jeopardizing the projects. Accordingly, we authorize the settlement amount of $164,000 for the Industrial/Environmental project area, $687,000 for the Advanced Commercial project area, and $458,000 for the Advanced Residential project area.

15.3.3 Customer Air Quality Improvement Sub-Program

Edison originally requested $2.498 million to assist Edison customers in meeting more restrictive air quality regulations in a cost-effective, source fuel-efficient manner. Edison's request was composed of four research project areas: (1) nitrogen oxides reduction, (2) reactive organic compound reduction, (3) toxic & halogen control, and (4) conservation based

environmental compliance. DRA recommended zero funding for each of these project areas.

In the settlement, Edison and DRA agreed to extend all four project area schedules. These schedule extensions reduce Edison's original request by $1.353 million.

Edison has stated that the intention of these programs is to assist its customers in meeting more restrictive air quality regulations in a cost-effective, source fuel-efficient manner. We deny funding for these project areas based on our policy regarding air quality programs that was articulated in D.93-12-043. In that decision, we stated that it is not appropriate to use ratepayer funds to support research to assist individual customers with their own end-use air quality compliance. (See, e.g., D.93-12-043, slip op. at pp. 143-144.) We believe that this assistance goes beyond the utility's traditional responsibilities to provide energy services.

Even though Edison's testimony on these project areas mentions that the technologies being developed will be energy efficient, the record does not support that this is the focus of Edison's efforts. Accordingly, we will deny funding for the four RD&D project areas.

15.4 Environment, Health & Safety Program

Edison originally requested $7.095 million to identify potential environmental, health and safety issues early and develop cost-effective solutions to minimize the impact of the utility's operations on the environment. DRA recommended a reduced funding level of $4.475 million.

In the settlement, Edison and DRA stated that the largest part of the proposed research related to identifying and managing air, water, and waste discharges from Edison generating facilities in an environmentally safe and cost-effective manner. The settlement's recommended funding level of $1.740 million reflects a shift in emphasis from long-term generation-related research to a

smaller, short-term management program consistent with the expected shift in Edison's role away from power generation.

15.4.1 Environmental Research Sub-Program

Edison originally requested $5.595 million to gather data on environmental media, natural habitats and the state of the environment in southern California. Edison would also develop techniques and computer-based planning models to simulate the response of the environment to changes in the types and quantities of waste streams released by Edison's operations and other regional industries and activities. DRA recommended a total funding level of $3.325 million composed of several project area adjustments.

In the settlement, Edison and DRA agreed to extend all three project area schedules, which reduced Edison's original funding request by $4.171 million.

Although the settlement results in a substantial reduction to this sub-program, we believe it is consistent with the expected shift in Edison's role away from power generation. We approve the settlement project area amounts for this sub-program.

15.4.2 Occupational Health & Injury Prevention Sub-Program

Edison originally requested $600,000 to identify and evaluate health and safety issues in the Edison work environment. Of this amount, $350,000 was for the Work Health Exposures project area. The remaining $250,000 was for the Ergonomics project area. DRA did not dispute the Ergonomics project area request but opposed the funding of the Work Health Exposures project area.

DRA asserted that Edison's request covered 63% of the total research cost. Although DRA generally believed that work health exposures research was a reasonable topic to explore, it did not believe Edison should lead the project. DRA suggested that the research be conducted by EPRI as a national research effort.

In the settlement, Edison and DRA agreed to cancel the Work Health Exposures project area and extend the schedule for the Ergonomics project area.

We find DRA's original testimony convincing and do not adopt any funding for the Work Health Exposures project area. We agree with the settlement's recommendation of extending the schedule for the Ergonomics project area and adopt the settlement's recommendation for this area.

15.4.3 Electric & Magnetic Fields Sub-Program

Edison originally requested $900,000 to conduct electric and magnetic fields research to provide information about the health impacts which result from the operation of the Edison system. DRA supported Edison's request in full.

In the settlement, Edison and DRA agreed to a funding level of $274,000 by extending the planned schedule. We adopt the settlement's recommendation.

15.5 Management, Support & Memberships Program

Edison originally requested $23.543 million to provide the administrative and management oversight, support and coordination for Edison's research program. DRA recommended a reduced funding level of $19.247 million for this program.

In the settlement, Edison and DRA agreed to $15.408 million. They stated that this reduced level reflects the need to lower the administrative costs associated with the streamlined research programs proposed in the settlement. The settling parties also agreed that Edison should be allowed to use up to an additional $458,000 (or $500,000 in 1995 dollars) of O&M expenditures for RD&D which would not be subject to the RD&D one-way balancing account. The parties agreed that Edison may use this funding for activities including studies of the effects of restructuring on Edison's research programs and priorities and related planning efforts. They stated that it is necessary that non-RD&D funds be used for this purpose because the Commission's adopted definition of RD&D does not allow use of RD&D funds for management studies or items of like nature.

We believe the additional $458,000 for RD&D O&M expenditures is necessary to develop the future business framework of Edison's Technology Planning and Development (TP&D) Department.[82] Activities for these funds include evaluating the impact of restructuring and the changing regulatory environment of the future role of RD&D, including appropriate organizational structures and management. Accordingly, we will authorize $458,000 for RD&D O&M expenditures. We discuss other issues below.

15.5.1 Research Management & Support Sub-Program

Edison originally requested $3.744 million to provide support services including research and project management, budgets, and accounting, administrative services, computer support, research communications and clerical support. Based on the individual adjustments discussed below, DRA recommended a funding level of $2.905 million.

Consistent with its recommendation that Edison not be allowed to conduct any incremental generation research, DRA recommended eliminating related management and support funding. DRA also recommended a reduction of $36,000 related to management consultant studies. In making this recommendation, DRA relied on the Commission's definition of RD&D adopted in D.82-12-005. In rebuttal, Edison clarified that the funding is for "contractor/consultant costs, not management consultant studies." DRA recommended further reducing Edison's funding request by $278,000 to remove proposed funds related to its low emission vehicle (LEV) program because DRA claims that this funding should be included with its LEV program funding requests that are a subject of the LEV Rulemaking (R.91-10-028).

82 In October 1994, Edison's RD&D Department was reorganized and renamed the TP&D Department.

In the settlement, DRA and Edison proposed reducing this sub-program funding by $2.147 million. This amount is also $1.308 million below DRA's original recommendation.

Based on our discussions of allowable expenditures for Edison's technical core research programs, we will similarly adopt the substantial reductions for the management support and operations-related funding. Therefore, we approve the settlement's recommendations with the clarifications set forth below.

Since "contractor/consultant costs" are allowable under our definition of RD&D, we will allow the $36,000 funding to be included in the settlement amount but with the specific proviso that it my be used for "travel and supply expenses, temporary non-Edison personnel, and facilities expenses" only.

In D.93-07-054, we directed utilities to request all utility funding requirements related to LEVs for a six-year cycle by filing special applications in the rulemaking. We do not think it is appropriate to authorize related LEV funding in this rate case. Therefore, we do not allow $278,000 of the settlement amount to be spent on LEV support.

15.5.2 Regulation, Contracts & Valuation Sub-Program

Edison originally requested $1.647 million to improve communications between the Research Department and regulatory agencies, ensure compliance with Commission and CEO guidelines, and provide efficient management of resources for the benefit of ratepayers. DRA recommended a total of $1.256 million.

In the settlement, DRA and Edison proposed reducing this sub-program funding by $1.145 million. We adopt the settlement's recommendation. Our result is based on deducting funding related to generation and removing all funding related to LEVs.

15.5.3 Industry Research Memberships Sub-Program

Edison originally requested $18.152 million for membership fees in collaborative organizations that pool the efforts and expertise of member utilities, outside experts and

other research organizations to research large scale, state of the art technology which Edison believes is beneficial to the industry. In particular, Edison requested membership fees for EPRI, California Institute for Energy Efficiency (CIEE) and Western Energy Supply and Transmission (WEST) Associates.

EPRI performs scientific research on the production, transmission, distribution and utilization of electric power for the intended benefit of utilities, their customers and the public. CIEE researches and demonstrates efficient end-use energy technologies and processes. WEST Associates provides a forum for utility managers to exchange information and attend conferences to discuss regional issues relating to electric utilities.

Consistent with DRA's recommendation that Edison not be allowed to conduct any incremental generation research, DRA recommended eliminating that portion of ratepayer funded EPRI membership that is associated with incremental generation research. In its opening brief, Edison stipulated to DRA's recommendation.

DRA believed that CIEE should move toward providing its energy efficiency products and services on a competitive basis. Accordingly, DRA believed that Edison should gradually reduce its guaranteed funding. Specifically, DRA recommended that Edison's funding be completely phased out by 1998. To accomplish this DRA recommended decreasing Edison's original funding request of $1 million per year to CIEE by $250,000 per year beginning in 1995. This recommendation resulted in an average funding level of $500,000 per year for the 1995 through 1997 rate case cycle. Although Edison had supported CIEE throughout its five years of operation, it was reevaluating its participation based on a review of CIEE's triennial report. DOE recommended that Edison's request be allowed. DOE has a strong and continuing interest in the CIEE program as a mechanism that meets the needs of California utility ratepayers and the goal of the DOE to support research that advances energy-efficient technologies. The University of

California (UC) also supported Edison's original recommendation. There were no positions in the record with respect to Edison's contribution to WEST Associates.

In the settlement, Edison and DRA stated that as Edison streamlines its research programs to respond to customers' needs for immediate rate reductions, memberships in EPRI will become a key means for accelerating the development of advanced technologies that can provide benefits for Edison's customers. While EPRI membership becomes more important, the actual cost of membership will be reduced below the levels originally proposed by Edison using EPRI's new "flexible funding" approach.

DRA and Edison proposed to cancel its memberships in CIEE and WEST Associates. The CIEE membership funding was eliminated because the parties believed the time frame for the end-use related research was too long. Edison stated that it may fund specific CIEE projects on a case-by-case basis consistent with the plan the CIEE board adopted to seek funds on a project-by-project basis rather than through membership dues. Other parties, such as the CEC, NRDC, UC, and TURN, continue to support Edison's original request for CIEE of $1 million annually.

The settlement funding for EPRI membership is the result of reduced funding for generation-related business units. We adopt the settlement's recommendation given our previously stated position regarding generation-related research. With respect to CIEE, we will adopt Edison's original request of $1 million because the record supports the fact that CIEE's collaborative research provides significant benefits to ratepayers. We adopt the settlement's recommendation to cancel Edison's membership in WEST Associates.

15.6 RD&D Policies

15.6.1. RD&D Audit Performed by Barrington Wellesley Group (BWG)

In D.91-12-076, we ordered a financial audit of Edison's RD&D activities and expenditures for the years 1988 through 1992 to be submitted in Edison's next (1995) general rate case. CACD retained BWG to perform this audit. CACD filed BWG's report in June 1993 and it was submitted as Exhibit 62 in this case. In its report, BWG made numerous recommendations regarding Edison's accounting practices and procedures, account classifications, RD&D account balances, and management issues. These recommendations are summarized on pp. II-4 through II-6 of Exhibit 62.

Edison originally requested that we accept all of the findings, conclusions and recommendations of the BWG audit except the recommendation to revise the reporting relationship and rotate the position of its General Auditor. DRA recommended that we adopt all but two of BWG's recommendations. DRA specifically objected to BWG's recommendations that allow expenses previously classified as capital to be booked to the balancing accounts and that implement a revision of the O&M criteria for capital assets. In the settlement, Edison and DRA agreed to accept all but these three BWG recommendations.

We addressed DRA's disputed recommendations in D.94-10-041. Edison continues to disagree with the BWG recommendation to revise the reporting relationship of the General Auditor and to consider instituting a job rotation policy for the General Auditor position. We will not order Edison to adopt the recommendation concerning the General Auditor but direct Edison to adopt all of BWG's other outstanding financial and management/policy recommendations.

15.6.2 RD&D One-Way Balancing Account

In D.87-12-066, we required Edison to establish and maintain a separate one-way balancing account for RD&D so that unexpended funds could be returned to ratepayers, with interest. We ordered that Edison follow the same procedures as ordered for PG&E in D.87-07-021. We provided for the continuance of Edison's balancing account for its 1992 through 1994 rate case cycle in D.91-12-076.

In June 1992, we adopted Resolution E-3275. This Resolution clarified that the one-way balancing account rules first adopted for PG&E and later adopted for Edison, SDG&E, and SoCalGas, apply on an annual, not general rate case cycle, basis. In PG&E's 1993 general rate case decision (D.92-12-057), we deviated from this annual balancing account reconciliation for the first time and allowed PG&E to reconcile its one-way balancing account over the rate case cycle in order to grant additional budgeting flexibility. Similarly, we allowed SoCalGas this same additional flexibility in its 1994 general rate case.

In this general rate case, Edison proposed to maintain the operation of the existing one-way balancing account but that it operate in accordance with our directives given to PG&E in D.92-12-057. Edison also concluded that the rate case cycle method should apply to its outstanding 1988-1991 rate case cycle and its 1992-1994 rate case cycle balancing account reconciliations. DRA disagreed. Although DRA was willing to adopt the new policy for Edison's 1995 rate case cycle, it asserted that all outstanding prior year account balances for the 1988-1991 general rate case and the 1992-1994 general rate case cycles should be reconciled on an annual basis consistent with the Commission policy which was in place during that relevant time period. In the settlement, DRA and Edison stated that their positions on this issue were unresolved and should be decided in this proceeding.

On March 31, 1995, Edison filed two advice letters to reconcile the one-way balancing accounts for its 1988-1991 and its 1992-1994 general rate case cycles. Contrary to Edison's original request in this case, Edison trued up the accounts on an annual basis. DRA protested one of the advice letters on other grounds.

We intend to address these advice letters and past general rate case balancing account reconciliations in Commission Resolutions. The reconciliation of Edison's balancing account over the 1995 general rate case cycle should be consistent with the rules set forth for PG&E in D.92-12-057.

15.6.3 Fund-Shifting Guidelines

Fund-shifting guidelines were not a litigated issue in this general rate case. However, for purposes of the settlement, DRA and Edison agreed that the fund-shifting guidelines adopted for PG&E in Resolution E-3376 should also apply to Edison. The CEC responded that given the severe budget reductions proposed in the settlement, it can no longer support these more liberal fund-shifting guidelines as it had in the past.

Given the linkage between the Commission's rules on RD&D one-way balancing accounts and fund shifting, we clarified in Resolution E-3376 that if a utility has received authorization to record expenditures in its RD&D one-way balancing account over the general rate case cycle, then it is reasonable to allow it to apply the fund-shifting guidelines over the rate case cycle as well. This is consistent with our intent to allow the utility to maintain flexibility in the timing of its RD&D expenditures. Since we have authorized Edison the balancing account flexibility, we think it is appropriate to grant Edison the corresponding flexibility with respect to fund shifting.

15.6.4 RD&D Royalty Memorandum Account

In compliance with D.91-12-076, Edison established the RD&D royalty memorandum account. This account ensures that Edison's share of royalties and licensing fees from customer funded

research is returned to the customers. In its original request, Edison proposed that the accounts recorded as of December 31, 1994 be returned to ratepayers as a credit to the ERAM balancing account, and that the disposition of the revenues be accomplished by advice letter filing on or before March 31, 1995. Edison further proposed that any revenues recorded in the memorandum account during the 1995 general rate case cycle likewise be returned to customers by advice filing as a credit to the ERAM balancing account.

DRA did not oppose these recommendations and the issue was not addressed in the settlement. We believe that Edison's recommendation is good policy, and adopt it. We extend the date of the advice letter filing to March 31, 1996. All revenues recorded in the royalty memorandum account for the 1995 general rate case cycle should be returned to ratepayers by an advice letter filing on or before March 31, 1998.

15.6.5 Funding Range

In D.90-09-045, we authorized the use of funding ranges for RD&D. In its original testimony, Edison requested establishing a funding range for the its next general rate case of 0.6% to 1.25% of gross operating revenues (GOR). DRA recommended that the Commission set a funding range of 0.3% to 0.6% of GOR. The CEC recommended a funding range of 0.6% to 1.0% of GOR.

In the settlement, Edison and DRA agreed to a funding range of 0.4% to 0.6% of GOR as the appropriate funding range for RD&D activities. The RD&D funding level proposed in the settlement is approximately 0.36% of forecasted GORs. The parties agreed to this reduced funding level in recognition of the short-term uncertainties surrounding the role of California's regulated electric utilities.

The Commission has adopted a funding range of 0.6% to 1.0% of GOR for both PG&E and SoCalGas and a funding range of 0.3% to 0.45% for SDG&E consistent with their historical RD&D funding

levels. Since we have authorized $25.571 million or approximately 0.36% of GOR in this decision for RD&D expenditures, we think that the proposed settlement range of 0.4% to 0.6% is appropriate given the uncertainties discussed above. This does not mean that Edison's RD&D funding requests cannot be higher (or lower) than the funding range. The funding range means that, if the utility's rate request for RD&D spending is within the funding range ordered in the current rate case, it would focus the discussion of RD&D on broad RD&D program directions. Only when the utility's RD&D program request rose above the ceiling or fell below the floor would detailed information be required.

16. Other Operating Revenues

16.1. Added Facilities

Edison has submitted proposed changes to Tariff Rule 2, Section H, Added Facilities. Edison stated that these changes reflect the results of an ongoing review of customer and Added Facilities issues that was begun in 1992 and which concluded that Edison's Added Facilities customers find their contracts difficult to understand and demand more options. Edison proposed to offer contracts that include options for the perpetual replacement of equipment, replacement of equipment for a 20-year term, and no equipment replacement. The CSB submitted testimony generally supporting these proposals, and no other party submitted testimony on this issue. We approve Edison's proposed changes to Tariff Rule 2, Section H. Because we address this issue and approve these changes today, the changes should not be retroactive to January 1, 1995.[83]

83 In the Interim Decision, we stated that we would not address the merits of each issue until this decision. Therefore, the CSB's petition for modification of D.94-12-045, requesting that the new added facilities charges go into effect on January 1, 1995, is denied.

16.2 Off-System Sales

16.2.1 Positions of the Parties Prior to the Settlement

Edison

Edison stated that under current ratemaking there is a disincentive at the margin for Edison to make off-system power sales above forecast levels. This is because Edison shareholders do not receive any of the revenues for sales above forecast levels but incur variable O&M expenses which are not recovered through rates. Edison proposed to remove forecasted O&M costs associated with off-system sales from the revenue requirement and to recover O&M costs associated with off-system sales through a variable/incremental O&M adder (adder) of 0.87 mills/kWh.

The proposed 0.87 mills/kWh adder consists of 0.21 mills for consumables, 0.07 mills for short-term standby savings, 0.09 mills for long-term standby savings, and 0.52 mills for overhaul costs. Consumables include water and chemicals necessary to maintain proper boiler chemistry and operation. Short and long-term standby costs consist of costs of maintaining units in standby to meet target reserve margins. Overhaul costs are costs of unit overhauls amortized among kWhs. Edison's estimate of these costs is derived from an analysis provided for its 1994 ECAC proceeding. This analysis included two separate methods of estimating costs, the QF in/out method and the incremental method.

Edison also sought to recover revenues in a memorandum account established by Resolution E-3369. Revenues tracked in this off-system sales adder memorandum account (memorandum account) represent O&M costs associated with off-system sales in excess of forecasted amounts. In this proceeding, Edison asserted that it is entitled to the full recovery of the 0.87 mills/kWh amount tracked in the memorandum account, no matter what value the Commission adopts as an adder for future off-system sales.

DRA

During evidentiary hearings, DRA disputed the amount of the adder, not whether the adder should be instituted in the first instance. In its brief following the evidentiary hearings, DRA disagreed with Edison's contention that an adder would provide an effective incentive for shareholders to maximize off-system sales. DRA noted that Edison's off-systems sales performance has been increasing in spite of the purported disincentive, and that there is no evidence that Edison lacks motivation to increase off-system sales without an adder. Even if the Commission approves an adder, the size of the correctly calculated adder would be so small as to be impotent as an incentive.

If the Commission does provide adder treatment, however, DRA recommended that the adder should be 0.28 mills/kWh in 1995 and should escalate 0.01 mills/year in 1996 and 1997. DRA agreed with Edison that consumables and short-term standby savings be included in the adder. The dispute between Edison and DRA was regarding the inclusion of overhaul costs and long-term standby savings. DRA also stated that Edison should recover any end balance in the memorandum account based on an adder value of 0.27 mills/kWh. DRA also urged the Commission to credit ratepayers for the use of Reclaim Trading Credits in support of off-system sales.

CAC

CAC stated that the true cost of off-system sales is dependent on a variety of factors and circumstances that change from year to year. CAC proposed that the Commission adopt an adder of 2.5 mills/kWh for the time being, and specify that the adder should be re-established annually in ECAC proceedings. CAC's 2.5 mills/kWh recommendation represented an average of Edison's proposed 0.87 mills/kWh adder and values derived from using the NARUC and "Labor" methodologies. CAC stated that its aim was to develop an adder, through compromise, which would fall within a

reasonable range of accuracy and most effectively reduce the risk of overcompensating shareholders for off-system sales. In its reply brief, the CAC responded to Edison's and DRA's criticisms of its methodology by offering to average DRA's recommended adder with the CAC's other figures, resulting in an alternative recommendation of 1.96 mills/kWh.

<u>TURN</u>

TURN urged the Commission to reject Edison's off-system sales proposal. Citing information TURN elicited in cross-examination, TURN argued that if Edison's generation were reduced by 25%, Edison believes that O&M adjustments to variable O&M costs would be unnecessary because any change in actual O&M costs would be too small to be of concern. Consequently, the same principle should apply to instances in which generation increases, such as a scenario in which off-system sales exceed forecast levels.

If the Commission chooses to provide adder treatment for off-system sales, TURN recommended that the adder should be 0.10 mills/kWh lower than requested by Edison to avoid double counting standby unit O&M costs that are provided for elsewhere in Edison's general rate case funding request.

<u>16.2.2 Settlement</u>

Edison and DRA were unable to agree on the appropriate value of the adder to be applied prospectively for the ratemaking treatment for off-system sales. Nor were they able to reach agreement on the appropriate value of the adder to be applied in determining the amounts Edison can recover from its memorandum account.

Edison and DRA agreed on the following items:

1. The Commission should further reduce the revenue requirements by 1595 gWh (the off-system sales forecast) times the adopted prospective variable/incremental O&M adder for 1995.

2. Edison should recover the prospective variable/incremental O&M adder amount for each kWh of off-system sales for sales delivered after January 1, 1995.

3. Edison should terminate entries to the memorandum account established by Resolution E-3369 after sales delivered up to and on December 31, 1994 are recorded, and the Commission should allow Edison to recover any ending amounts based on the adopted retrospective adder.

4. Edison should credit retail ratepayers for the value of RECLAIM trading credits[84] which are instead consumed in making off-system sales. This credit will be based on the value Edison will implement in its system dispatch computer to reflect the value of RECLAIM trading credits for purposes of making transaction decisions. Implementation will occur no later than December 31, 1995. The value of RECLAIM trading credits shall be credited to ratepayers before any recovery of variable/incremental O&M costs by shareholders.

16.2.3 Discussion

The Adder

We recognize the benefits ratepayers receive from superior off-system sales performance, and believe it is appropriate to compensate shareholders for costs associated with these sales. The issue of the appropriate methodology for calculating the adder is more problematical, for our record is

84 RECLAIM trading credits are airborne emissions allowances issued by the South Coast Air Quality Management District. These allowances are necessary for district businesses wishing to engage in activities that create certain airborne pollutants. Although initial issuance of RECLAIM trading credits is free to existing businesses, annual allocations are limited and RECLAIM trading credits can be traded among businesses. For this reason, RECLAIM trading credits have a market value.

inadequate to approve any specific methodology. However, given that we believe it is appropriate to provide an incentive to shareholders to make off-system sales, we determine a reasonable value for the adder based on the existing record. We adopt an adder value of 0.53 mills/kWh.

We agree with the CAC that estimates provided by other parties ignore some variable costs pertinent to off-system sales. However, we are not confident that the CAC estimate has been tailored to the particular regulatory mechanism existing in California today. For instance, CAC states that fuel varies with off-system sales, and should be included in a comprehensive estimate of off-system sales variable costs. But to do so could result in a double counting because compensation for costs would be provided both through the adder and through the ECAC proceedings. The CAC estimate may double count in other cost categories as well.

We note that the Edison, DRA, and TURN estimates are consistent on the value of consumables. TURN disagrees with including any standby costs in the adder. DRA believes that costs of keeping units on long-term standby should not be attributed to off-system sales since off-system sales are possible only because there is long-term excess capacity and should be reduced when long-term reserves diminish. Even though Edison states that it will not return long-term standby units to service to make spot market sales between 1995 and 1997, it still believes we should include long-term standby savings in our adopted value because its second study (the incremental method) arrived at approximately the same value for the adder as did the methodology which included long-term standby savings. We agree with DRA and do not include long-term standby savings in our adopted value for the adder.

Edison and DRA differ as to whether a value attributable to overhaul costs should be included in the adder. If overhaul costs are fixed, they would not vary with off-system sales since they would be covered in O&M cost categories that are not

associated with off-system sales. If they are variable, then they should be estimated and included in the adder.

Although DRA states that it believes that overhaul costs are, in theory, partially variable, it also states that the degree of such variability is difficult or impossible to quantify in practice. DRA does not believe that the evidence in this record demonstrates any quantifiable variable component of overhauls. DRA explains that Edison instituted a Condition Based Maintenance (CBM) program in 1992, which departs from using operating records as the basis for regular overhaul scheduling, but instead bases maintenance on the condition of the plant. DRA argues that Edison's characterization of CBM undermines any functional relationship of overhaul costs and kWh, and does not support the argument that overhaul costs are fully variable. DRA also points out various weaknesses in the assumptions which underlie Edison's attempt to estimate overhaul costs.

We agree that DRA has set forth compelling weaknesses in Edison's approach to determine the value for overhaul costs which we should attribute to the adder. However, we also recognize that even DRA believes that overhaul costs, in theory, are partially variable, and for this reason we hesitate to assign a value of zero to these costs. We therefore assign a value for overhaul costs of 0.26 mills/kWh, which is half of the value proposed by Edison.

We adopt an adder value of 0.53 mills/kWh to be applied prospectively for the ratemaking treatment for each kWh of off-system sales delivered after January 1, 1995, subject to our discussion of RECLAIM below. We also reduce Edison's revenue requirements by 1,595 GWh (the off-system sales forecast) times 0.53 mills/kWh.

We reject the CAC's suggestion that the Commission revisit the adder values in each annual ECAC proceeding. We have repeatedly stated that we would not permit methodological changes to the calculation of the QF O&M adder in ECAC proceedings. (See,

e.g., D.94-12-047, slip op. at p. 23.) Similarly, the ECAC proceeding is not the forum to revisit this issue. However, we note that the ALJ granted Edison's motion to strike DRA's rebuttal to Edison's additional off-system sales testimony without prejudice to DRA to introduce such testimony in another proceeding such as the Investigation portion of Edison's PBR application. We affirm the ALJ's ruling.

The record developed in this case was regarding the appropriate adder for off-system sales. Thus, we agree with Edison's witness Silsbee that the value adopted in this proceeding for the O&M adder should not be regarded as precedential for setting the appropriate value for QF avoided O&M costs in future ECAC proceedings.

<u>RECLAIM</u>

We agree with the concept advocated in the hearings by DRA that Edison credit retail ratepayers for the value of RECLAIM trading credits which are instead consumed in making off-system sales. The settling parties more specifically articulated how this DRA proposal should be implemented. We adopt this recommendation which is set forth as Item 4 in Section 16.2.2, adjusted for a January 20, 1996 implementation.

<u>Memorandum Account</u>

We disagree with Edison's contention that it is entitled to recover the recorded 0.87 mills/kWh tracked in the memorandum account established by Resolution E-3369 notwithstanding the fact that we approve a lesser value for the adder in this decision. The intent of Resolution E-3369 is to authorize the level of costs to be recorded in a memorandum account, and to have the appropriate rate determined in the off-system power sales incentive mechanism application (OPSIM) or other proceeding (such as this general rate

case) prior to the Commission's authorization for rate recovery.[85] We direct Edison to terminate entries to the memorandum account established by Resolution E-3369 after sales delivered through December 31, 1994 are recorded and allow Edison to recover any ending amounts based on the adopted adder of 0.53 mills/kWh and the difference between forecast and recorded off-system sales.

17. Rate Base Issues

Electric plant-in-service encompasses plant addition expenses requested by Edison related to the following categories: steam, nuclear, hydraulic, other plant, transmission, distribution, and general. Also included are plant overheads and plant held for future use.

During the course of the hearings, Edison and DRA modified their positions to concur on a number of recommendations. At the close of hearings, there was a $20.861 million difference between Edison and DRA. Some of this difference is resolved by our resolution of other issues in this decision (e.g., customer growth). We address the other outstanding issues below.

85 For example, page 3 of Resolution E-3369 states:

> "This Advice Letter does not request a change in ratemaking practices related to off-system sales revenues. It does, however, provide a memorandum account procedure to track certain revenues. The Commission may change the ratemaking procedures in the OPSIM Application."

Also, Ordering Paragraph 3 of the resolution states:

> "The adder of 0.87 mills per kWh shall remain in effect until changed by the Commission in the OPSIM or other appropriate proceeding <u>during the interim period prior to the Commission's authorization for rate recovery</u>." (Emphasis added.)

<u>17.1. DRA's Plant-In-Service Reductions</u>

<u>Steam and General Plant</u>

In the comparison exhibit filed after the evidentiary hearings (Exhibit 167 at p. 148), DRA recommended that Edison's plant-in-service be reduced by $1.668 million in the steam category and $0.366 million in the general category. Edison objected to this proposal on the grounds that this is a new disallowance which DRA developed since the close of hearings and Edison and other parties did not have an opportunity to cross-examine DRA on this issue.

DRA disagreed. DRA stated that their witness indicated that his recommendation would also contain a adjustment for credit in insurance recoveries impacting FERC Account 144 (accumulated provision for uncollectible accounts), Account 101 (electric plant in service), and Account 397 (telecommunication equipment). However, this DRA witness was unable to make a final recommendation when he appeared at the hearings because of a late data response from Edison. The DRA witness stated that DRA would file errata once he obtained the necessary information from Edison. (R.T., Vol. 30 at pp. 3455-3456.) The settling parties agreed with Edison's request in order to obtain the overall benefits of the settlement.

It does not appear that DRA filed errata before the close of the hearings, but instead included its proposed adjustment in Exhibit 167 (the comparison exhibit filed after the 1994 evidentiary hearings). DRA has given us insufficient, summary testimony on which to evaluate its recommendation which, because of when it was made, was not subject to cross-examination. We therefore deny DRA's recommendation.

<u>Nuclear Plant</u>

We address DRA's recommended reduction due to SONGS Units 2 & 3 Cycle 8 refueling costs in Section 6. DRA also recommended reductions of (1) $1.284 million associated with the

SONGS Environmental Mitigation Project's Marine Education Center; (2) $0.498 million for the SONGS Power System Stabilizer, a portion of the SONGS Fish Hatchery Project and the SONGS Offsite Emergency Planning Project, and (3) $2,000 of overheads. Edison stated that even though the Marine Education Center and the power system stabilizer work were not reviewed by the DRA's nuclear witness, they were properly accounted for as nuclear plant and should be included in this classification. Edison also argued that the DRA witness who reviewed SONGS Environmental Mitigation Project and Power Systems Stabilizer Projects did not recommend a specific reduction to Edison's estimated project costs, or to the Fish Hatchery or Offsite Emergency Planning Project. We do not approve DRA's requested reductions.

17.2 TURN's Plant-In-Service Reduction

TURN recommended a reduction in 1995 plant-in-service of $9,514,000 to address what it terms to be a double recovery which occurred in the last five years due to an Edison accounting change. TURN stated that Edison changed its accounting policy between general rate cases in a way that allowed costs to be capitalized at the same time that expense recovery was obtained for the same costs in the 1988 and 1992 general rate cases. As a remedy, TURN proposed that the Commission remove the associated plant from Edison's plant-in-service. TURN did not argue that Edison is attempting to achieve a double recovery on these accounts in this general rate case.

Edison stated that it could not recall that this double recovery happened given the hundreds of items at issue in its 1992 general rate case. Moreover, Edison argued that making adjustments now to the revenues established in the 1992 general rate case would be retroactive ratemaking. Edison also stated that if the Commission grants TURN's recommendation, TURN overstated its recommendation by approximately $3 million.

Our task in this general rate case is to set Edison's revenue requirement for test year 1995, not to make adjustments to its test year 1992 general rate case. In this rate case, Edison removed items that were previously expensed but are now capitalized from the base used for expense estimates. (See Exhibit 204 at p. 45:10-14.) We therefore deny TURN's requested reduction.

17.3 DRA's Recommendations Regarding Edison's Plant Forecasting Model

DRA made several nonmonetary recommendations with respect to Edison's plant forecasting model for Edison's next general rate case. First, DRA stated that Edison's forecast for the allowance for funds used during construction (AFUDC) could be more accurate if Edison made certain modifications to its computer model so that AFUDC was calculated for each project addition. DRA also recommended that Edison's model provide the operative dates by month for each project, calculate a weighted average balance for each project, and develop overheads for each project. Edison stated that, although it has not quantified costs, it believes that the costs of DRA's proposed modifications (other than providing operative dates by month for each project, which Edison states it provides in its workpapers) would outweigh the benefits. DRA also did not present a cost/benefit analysis.

We cannot be assured of the merits of DRA's proposals because we are not assured on the basis of the record that the benefits outweigh the costs. Therefore, we deny DRA's recommendations.

17.4 Working Cash

Working cash is the capital the company "floats" ratepayers to maintain its operations. Generally, working cash is calculated by determining the difference between the date a customer bill is rendered and the date the associated payment becomes available for use. Working cash also takes into account the average period between the date Edison is rendered a bill and

the date it pays the bill. (These calculations are referred to as the "lead-lag" study.) Because shareholders float the difference, they are entitled to earn a rate of return on the associated amount.

In this proceeding, Edison's and DRA's differences with respect to the working cash estimate resulted from the two parties' different O&M expense estimates. Similarly, if we adopt other parties' recommended O&M reductions, this would also affect the working cash estimate and would be reflected in our tables.

TURN recommended three specific reductions to Edison's working cash estimate which we address here. TURN recommended that the Commission recognize lower levels of test year expense and more accurately calculate the lag days for expenses listed as "fuel oil" and exclude Minnesota state income taxes from the calculation. Edison did not address these two issues in its briefs filed after the evidentiary hearings. We therefore adopt TURN's recommendations on these two issues.

Edison disputed TURN's recommendation that revenues from Edison's Resale Customers be removed from the lag study used to determine working cash balances. Specifically, TURN recommended that since Edison's resale customers take at least one-third longer than Edison's retail customers to pay their bills, resale customers are presently causing all of Edison's other customers to pay for a working cash requirement which exceeds the level of working cash that would be required if the resale customers were not included in the calculation. TURN's proposed remedy was to exclude resale lags from the calculation of revenue lag days, reducing the average number of lag days from 43.59 days to 43.29 days, and reducing Edison's working cash requirement (and its revenue requirement) by $5,509,000.

Edison argued that this adjustment is improper because it reflects only the revenue impact caused by the resale customers but ignores any offsetting impact to expense lags. Edison also stated

that TURN's proposed adjustment is already reflected in the jurisdictional allocation of rate base to resale customers. Finally, Edison stated that TURN's recommendation is contrary to Standard Practice U-16, which was used by both Edison and DRA in determining their working cash estimates.

TURN argued that the Commission has indicated that U-16 needs revision and therefore will make exceptions to this Standard Practice in appropriate situations. (See e.g., California Water Service Company, D.93-01-025, 47 CPUC2d 580, 593; D.93-12-043, slip op., at p. 87.) However, we are concerned about Edison's assertions that TURN's proposed adjustment is already reflected in the jurisdictional allocation of rate base to resale customers. Because we wish to avoid "double-counting" reductions, we deny TURN's request on this issue.

17.5. Nuclear Decommissioning Expenses

DRA reviewed Edison's cost studies for decommissioning SONGS and Palo Verde and found them to be satisfactory for the purposes of developing Edison's test year 1995 nuclear decommissioning expense. No other party contests these expenses.

Edison stated that it is required to file a revised Schedule of Ruling Amounts (SRA) with the Internal Revenue Service to reflect any changes in the amounts of nuclear decommissioning costs authorized in the utility's cost of service.[86] At the Update hearings, Edison stated that it was advised after the close of the evidentiary hearings that when filing for future SRAs, the Internal Revenue Service now requires unit specific information on

86 According to Edison, a SRA is a levelized schedule of annual amounts that represent trust fund contributions required to fund the portion of the total estimated cost of decommissioning attributable to the remaining life of the nuclear power plant at the time that a decommissioning fund is initiated.

decommissioning costs from the utility's most recent cost of service proceeding such as this general rate case. Edison was also advised that the Internal Revenue Service finds it helpful if unit-specific information is included in the final decision. Edison submitted the following unit specific information which no party objected to and which we adopt. (See Exhibit 169 at Appendix B, p. B-1.)

Line No.	Unit	Qualified ($000)	Nonqualified ($000)	Total ($000)	For Years
1	SONGS 1	1,943	3,374	5,317	1995 2004
2	SONGS 2	30,121	1,004	31,125	1996 2013
3	SONGS 3	35,071	0	35,071	1996 2013
4	PVNGS 1	9,250	0	9,250	1995 2024
5	PVNGS 2	9,183	0	9,183	1995 2025
6	PVNGS 3	9,876	0	9,876	1995 2027
7	TOTAL	95,444	4,378	99,822	

17.6. Ratemaking Treatment of Fuel Inventory Carrying Costs

17.6.1. Positions of the Parties - Prior to the Settlement

Edison proposed that parts of its fuel oil, nuclear fuel, and coal inventories have permanent components which should be included in rate base and removed from ECAC treatment. What that means is that ratepayers would bear carrying costs for the fuel inventory deemed permanent at the rate of the weighted average cost of capital rather than the three-month commercial paper rate. Edison's specific proposal is that approximately $64 million of fuel oil, $73 million of nuclear fuel, and $5 million of coal be considered permanent and be rate based.

Edison defined permanent fuel inventories "to be the minimum amount that must be maintained over the long term to assure continuing and reliable operations." (Exhibit 212 at p. 2.) In support of its proposal, Edison uses examples of tools, materials, and supplies that are rate based.

Edison believed its position is consistent with a financing principle that the life of an asset should match its financing instrument. Edison stated that the benefits of its proposal are that (1) it is consistent with the nature of the asset and the financing of other utility inventories; (2) it is more consistent with FERC treatment of fuel inventories; (3) the shareholders will incur the risk of variations of the portion of the fuel inventory delineated as permanent between rate cases; (4) it will increase Edison's financial flexibility and minimize the overall cost of capital; and (5) it will provide an incentive to carry lower costs of inventory. Edison stated that although it is difficult to quantify the extent to which Edison's capital costs are increased by the need to hold a permanent layer of short-term debt, each additional basis point added to the cost of capital would increase costs by about $1.5 million. Edison cited to a letter from Standard and Poor's to CACD, which stated that financing permanent assets exclusively with short-term debt impairs the utility's overall earning power and cash generating ability.

DRA disagreed with Edison. DRA's position in hearing and brief differed slightly. In hearings, DRA stated that rate base treatment of fuel inventories is generally not justified, but concedes that dead storage volumes could be considered permanent and receive rate base treatment. DRA's primary disagreement with Edison was in the definition of permanent and temporary fuel inventory. DRA considered as temporary any fuel available to be consumed for any generation. DRA did not believe Edison has met its burden of proof in delineating what portion of its fuel inventory supply is permanent under DRA's definition, and therefore did not agree that any fuel oil or coal inventory rate base treatment is justified, or that the consequences of this new ratemaking proposal are beneficial to ratepayers. DRA disagreed with Edison that there are any permanent characteristics to the

batches of nuclear fuel, as each batch is rotated on a two-year cycle.

DRA explained that the cost of using equity rather than debt is higher to the ratepayer for several reasons, including the impact of income tax that must be recovered with a return on equity. Assuming a carrying cost to ratepayers of 13.59% for permanent treatment, compared to the 3.5% short-term interest rates currently applied, DRA estimated that adopting Edison's proposal for permanent fuel inventories will result in an additional cost to ratepayers of $14.9 million. (Exhibit 402 at p. 17-2.)

In its brief, DRA requested that the Commission deny Edison's request because it would impede any future ratemaking efforts to unbundle rates for reform balancing accounts. DRA stated that Edison seeks to impose $14.9 million to $13.5 million costs on ratepayers for an insurance policy premium which it has not demonstrated to be cost-effective. DRA also stated it never agreed to rate base permanent fuel oil inventories on an ongoing basis. Alternatively, DRA stated that if the Commission grants Edison's request, it should be limited to placing into rate base the following portion of fuel oil: 365,000 barrels of dead storage and 800,000 barrels of central system storage.

17.6.2. The Settlement

The settling parties agreed for ratemaking purposes to exclude from rate base in the 1995 general rate case cycle all of the barrels of fuel oil inventory, coal, and the portion of in-core nuclear fuel that Edison requested be included in rate base. The parties agreed that Edison should be able to recover short-term debt carrying costs on the total recorded fuel oil, coal, and nuclear in-core fuel inventory subject to reasonableness review. This ratemaking treatment should remain in effect during the remainder of the rate case cycle in ECAC proceedings for fuel oil and coal, and through January 31, 1996 for in-core nuclear fuel.

17.6.3 History of Ratemaking Treatment of Fuel Inventory Carrying Cost

Since Edison's proposal is a change from the status quo, it is useful to understand the background regarding this Commission's treatment of fuel inventory carrying costs. Fuel inventories are evaluated annually in ECAC proceedings. The cost of holding or storing fuel inventory is known as the carrying cost. The ratepayer does not pay for the fuel until it is used to generate electricity. However, the ratepayer pays for the cost of holding or storing the fuel until it is burned.

Before the ECAC was introduced, fuel inventories were set in biennial general rate cases and were given rate base treatment. In D.85-12-107, the Commission addressed the question of the proper treatment of fuel inventory carrying costs. At issue here was a public staff (DRA's predecessor) proposal that an electric utility should charge ratepayers the cost of carrying its fuel oil inventory at some form of short-term debt rather than at the authorized rate of return. Edison supported permanent capital financing of its entire fuel oil inventory, arguing that this was appropriate since fuel oil inventory is maintained on a permanent basis to ensure reliable service. In support of this position, Edison made the same arguments that it is making in this general rate case, namely, that that sound financial principles suggest that fuel oil inventory should be financed with permanent capital rather than short-term debt (i.e., the life of an asset should match its financing instrument).

The Commission disagreed with Edison:

> "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 that must be recovered with a return on equity. Second, the

> balancing account associated with ECAC expenses was not designed to reward the company with its rate of return on a non-ratebase item but to shield the company from wide swings in fuel expenses. Finally, the low risk nature of fuel oil inventory calls for a different ratemaking approach. (D.85-12-107, 20 CPUC2d 111, 112, as modified in D.86-05-095, slip op. at p. 2.)

The Commission stated that the major principle underlying ECAC has been the volatility of fuel prices and resource mix, which are matters beyond the control of utility management. The purpose of the ECAC balancing account is to protect management from its inability to control these expenses. 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 has been guaranteed recovery of its rate of return on a low-risk asset. This result was never intended to occur through ECAC procedures." (Id. at p. 3.)

The Commission explained that even if the resulting savings to ratepayers from this decision were insignificant, it would still make the change "to properly balance the risks and opportunities created by ECAC for management." (D.85-12-107, 20 CPUC2d at 114.)

In D.87-12-066, 26 CPUC2d 392, the Commission extended the above holding to Edison's coal and nuclear fuel inventories. Edison requested rate base treatment of a portion of the nuclear fuel it planned to purchase (it had been leasing the fuel), and for its coal reserves. Edison argued that "financing nuclear fuel with permanent capital as reflected in imbedded-cost of debt appropriately matches asset and liability life and risk." (26 CPUC2d at 433.)

The Commission stated:

> "Although Edison 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 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 term debt in deriving the carrying cost associated with nuclear fuel, it does not justify rate base treatment." (Id.)

The Commission went on to state 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 and land ... fuel should not be afforded rate base treatment, regardless of its characteristics." The Commission directed Edison 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 ECAC balancing account. (Id.)

The Commission again addressed carrying cost calculation issues in D.91-05-054, 40 CPUC2d 469. This decision, in relevant part, ordered that CACD hold a workshop to to provide input from energy utilities on a generic basis on their concerns, if any, regarding the Commission's policies on funding fuel oil in inventory and for the accompanying economic evaluation of inventory management decisions. The three electric utilities and DRA participated in the workshop. The participants reached a consensus with respect to fuel oil inventory, namely, that fuel oil inventories should be split into two separate components for ratemaking purposes: a permanent component to be rate based and financed with long-term debt, and a temporary component to continue to receive ECAC balancing account treatment and to be financed with short-term debt.

The Commission recently addressed the carrying cost issue in D.93-01-027, 47 CPUC2d 682. In that proceeding, Edison requested authority to make certain changes to its fuel-related rate levels that would result in a net revenue decrease for the

1993 forecast period. Two of these changes involved the calculation of fuel inventory carrying costs. First, Edison requested that the short-term rate used both to forecast costs and to account for actual costs be the "yield" rate as opposed to the "discount" rate. It argued that the yield figure better reflected the actual cost to the borrower. DRA argued that the published rates for three-month commercial paper, which are figured on a discount basis, should be used to calculate carrying costs.

The Commission noted that it was "determining a ratemaking principle, not Edison's actual costs of carrying its fuel inventory." (D.93-01-027, 47 CPUC2d at 693.) The Commission continued,

> "As Edison testified in this case, it issues short-term debt and long-term debt as needed for all corporate purposes throughout the year. None of this debt, as far as we can ascertain, is earmarked for fuel oil carrying costs." (Id.)

Citing D.85-12-107 as standing for the principle that ratepayers' share of the carrying cost of fuel inventories has been held to be the cost of "short-term debt," the Commission found that Edison's calculation of short-term debt was within the meaning of that term. Thus, it approved the slightly higher yield figure for the purpose of calculating the forecast and actual carrying costs.

DRA also requested that the Commission apply one short-term rate to calculate carrying costs for all fuels, including nuclear fuel. (In D.88-09-031, 29 CPUC2d 314, 342, the Commission authorized Edison to finance nuclear fuel with a blend of short- and intermediate-term debt.) DRA argued that one short-term interest rate should be used to calculate the carrying costs of all fuel inventories, especially since at that time Edison was not actually financing its nuclear fuel with any intermediate-term debt.

The Commission agreed with DRA, stating, "[W]e see no difference in the financing of these fuels. Edison and other utilities can use a myriad of borrowing arrangements including intermediate-term debt ... to finance carrying costs." (D.93-01-027, 47 CPUC2d at 694.) As noted earlier, the utility is free to finance these inventories however it pleases, but the Commission has decided to limit the ratepayer's share in that expense to the short-term interest rate.

In a settlement reached in Edison's 1993 ECAC proceeding (see D.94-01-040), Edison and DRA agreed to the level of fuel oil inventories to be considered permanent, and agreed that this level be placed in rate base for 1994. Additionally, the parties agreed that the issue of whether coal and nuclear inventories should be given similar ratemaking treatment would be deferred until the 1995 general rate case. The parties also agreed that the settlement agreement should not be deemed as precedent in any other proceeding, and reserved the right to advocate different positions in other proceedings.

17.6.4 Discussion

We are not convinced that the "permanent" and temporary" distinction of fuel inventory is the appropriate line of inquiry in order to determine whether Commission policy should be changed in this instance.[87]

Prior to 1985, the Commission permitted a utility to receive its authorized rate of return on fuel inventory. In making the decision in 1985 that the utility should finance its fuel oil

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[87] Both Edison and DRA apparently agreed in concept at a workshop that fuel inventory had a permanent and temporary component. Yet, these two parties cannot agree on a definition of permanent or temporary for this purpose. Nor did the Commission ratify that the results of the workshop were somehow binding on the parties in this general rate case.

inventory through some form of short term debt rather than shareholder equity, the Commission primarily focused on a risk analysis. The Commission described fuel inventory as low risk, because unlike other rate base assets, fuel oil inventory is subject to balancing account treatment. "In effect, Edison has been guaranteed recovery of its rate of return on a low-risk asset. This result was never intended to occur through ECAC procedures." (D.85-12-107, as modified by D.86-05-095, slip op. at p. 3.)

We do not believe that the risk Edison is offering to assume is significant enough to justify a change in financing of the carrying costs, especially when Edison has not met its burden of proof in demonstrating the rate impact and cost-effectiveness of its proposal. The portion of the fuel oil inventories which Edison proposes to rate base are the portion of the inventories whose volume is more stable than the remaining portion (i.e., according to Edison, the minimal inventory which should be maintained over the long term to assure continued reliable operations). Therefore, the risks associated with forecasting values for fuel inventories and having to replace an inventory at a higher cost appear to be less than the risks associated with the balance of the inventory.

As stated in D.85-12-107, even if the resulting savings to the ratepayers were insignificant, the Commission stated it would hold that Edison could charge ratepayers carrying costs for fuel inventories only at short-term debt "to properly balance the risks and opportunities created by ECAC for management." (20 CPUC2d at 114.) Here, we do not believe that Edison's proposal changes the risks to the degree that a different rate of recovery on carrying costs is warranted.

Moreover, we stated in D.85-12-107, as modified in D.86-05-095, slip op. at p. 2, that "(t)he cost of using equity rather than debt is higher to the ratepayer because of the income tax that must be recovered with a return on equity." Although Edison argues that the ratepayer would be better off under its

proposal because investors view a company with less short-term debt as more stable, Edison has not convincingly demonstrated the effect on ratepayers (tax and otherwise) of its proposal.

Edison's general argument that ratepayers will benefit if it is allowed to finance fuel inventories with long-term debt has several weaknesses. For example, Edison could request that it be compensated for detrimental effects, if any, of its short-term debt in its cost of capital proceeding. Also, the Commission's chosen method of calculating carrying costs does not dictate any particular financing approach. As stated in D.93-01-027, 47 CPUC2d at 693, the short-term interest rate is a ratemaking device only and represents the ratepayers' share of this expense. That decision also noted that no particular debt instrument could be linked to the fuel inventories in question. (Id.)

We believe it more efficient to include determinations of the reasonableness of fuel inventory levels in the ECAC proceeding. 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.

17.7. Kramer-Victor Transmission Line

The settling parties agree that Edison's request to recover Kramer-Victor transmission line costs should be determined in A.89-03-026. This issue is removed from this case, and no costs for this item should appear in Edison's revenue requirement resulting from this case.

18. Taxes

Edison presented evidence on state and federal income taxes, payroll and miscellaneous taxes, and ad valorum taxes. DRA was the only party to address these issues. The tax amounts at issue are due to Edison's and DRA's different expense, capital and

revenue estimates, which are addressed elsewhere in this decision. Therefore, there are no outstanding tax issues necessary for us to resolve.

19. Total Compensation

19.1 Procedural Background

Prior to the evidentiary hearings, before the parties served all testimony on the total compensation issue, Edison and DRA reached an impasse on the issue of preparing a total compensation study as required by Edison's test year 1992 general rate case, D.91-12-076.[88] In early 1993, Edison contracted a total compensation study by Hewitt Associates (Hewitt). The parties disagreed regarding the level of DRA's involvement in the development of the study. In any event, as the study neared completion, DRA developed concerns regarding the level of access DRA would have to the data base and computer algorithms used to develop Edison's compensation study.

On February 11, 1994, Edison and DRA filed concurrent motions regarding a total compensation study. Edison sought an order directing DRA to comply with terms of a prior DRA letter which it claimed resolved access questions pertaining to the Hewitt study and to issue two Requests for Bids (RFBs) jointly with Edison for studies on executive and nonexecutive compensation. Edison also sought an order specifying the appropriate level of access to compensation survey data, arguing that it is standard industry practice not to disclose unmasked company-specific data to

88 Finding of Fact 17 of D.91-12-076 states:

"In Edison's next GRC, Edison and DRA should continue their joint studies on compensation, with more emphasis on total compensation, total benefits as a percentage of cash compensation, and the distribution of total compensation among firms." (42 CPUC2d at 741.)

outside persons, including Edison. Among other things, DRA sought an order releasing it from having to develop a joint database with Edison and requested that the Commission direct Edison and DRA to procure a consultant to produce a common database on total compensation to be available to all parties in the proceeding.[89]

After consultation with the Assigned Commissioner, the ALJ issued a March 1, 1994 ruling (the ALJ ruling) addressing total compensation testimony. The ALJ ruling reminded the parties that, pursuant to Ordering Paragraph 44 of D.91-12-076, Edison is required to make an affirmative presentation in this general rate case on the appropriate level of total compensation.[90] The ALJ ruling made it clear that a letter from DRA to Edison could not modify Ordering Paragraph 44, and that it is the Commission, not DRA, which will determine if Edison has met its burden of proof on the issue of employee compensation.

The ALJ ruling stated that both Edison and DRA were at fault for the impasse, and chastises them for not bringing their

89 DRA also filed a Petition for Modification of D.91-12-076 requesting it be released from the obligation of developing a joint database with Edison. The Commission granted DRA's petition in D.94-05-009. In that decision, we also stated that both Edison and DRA are partly responsible for failing to produce joint studies on total compensation.

90 Ordering Paragraph 44 of D.91-12-076, 42 CPUC2d at 761, states in pertinent part:

> "In its next general rate case, Edison shall file or serve testimony on the following topics:
>
> "a. wages and salaries, with increased emphasis on total compensation, total benefits as a percentage of cash compensation, and the distribution of total compensation among comparable firms."

deadlock to the Commission's attention earlier. The ALJ Ruling resolved the problem by setting forth the following guidelines.

> "Edison is directed to prepare and present an exhibit in this proceeding on total employee compensation. The exhibit may consist of the Hewitt study or a different study, so long as the following conditions and access are met. Edison's employee compensation exhibit should specify the compensation provided to employees and officers at each occupational level in the form of cash (including wages, salaries, bonuses, commissions, and all other cash compensation) and benefits (including health care packages, pension benefits, stock options and all other non-cash benefits). The exhibit should provide information regarding (1) total compensation, including benefits; (2) total benefits as a percentage of cash compensation; (3) the corresponding company's (Edison) grade level for each position matched; (4) the distribution of total compensation among comparable firms; and (5) Edison's total compensation exhibit should indicate if the same or different comparator groups are used to develop the components (i.e., incentives, benefits, and base pay) of total compensation for all portions matched in Edison's exhibit. Edison should present the information with the understanding that it has the burden of proof in this proceeding to justify employee compensation." (ALJ Ruling at p. 13.)

With respect to access and confidentiality concerns, the ALJ Ruling stated:

> "[I]n balancing the confidentiality concerns against the need to create a complete record in this proceeding on total compensation, it is ruled that: (1) the disaggregated data and algorithms which Edison employs in its study shall be accessible to other parties to this proceeding who sign a standard nondisclosure agreement; (2) Edison must provide a list of the companies used in any comparative study. However, Edison may mask the identity of specific companies which may relate to specific disagreggated data; and (3) when Edison serves its testimony ..., it shall make available to any requesting party its work papers and a

description of the operation of the computer algorithm, with the identity of specific companies which my relate to specific disaggregated data masked if necessary. (ALJ Ruling at p. 14.)

19.2 Position of the Parties Prior to Settlement

Edison

Edison stated that its current employee compensation strategy is to pay its employees at prevailing market levels. Edison believes this philosophy is not only reasonable but beneficial to Edison's customers because it enhances employee performance. Edison sponsored an executive compensation study (Exhibit 32, Appendix A), based on data from proxy statements, and a nonexecutive compensation study (Exhibit 55). Edison concluded that its executive compensation is 37% below the market median, and its nonexecutive compensation is 0.8% above market level.[91] Edison argues that its testimony supports the reasonableness of its employee compensation request for the nonexecutive employees, even though its request is marginally above market, because of PG&E's test year 1993 general rate case, D.92-12-057, which concluded that PG&E's compensation strategy of 5% above market, was reasonable given the record and the propensity of wage surveys to have an inherent margin of error.

91 Edison's Exhibit 55 states that for executive positions, its analysis did not include disaggregated data for executive positions as required by the ALJ ruling, because neither of Edison's consultants was willing to disclose disaggregated data for executive positions due to the sensitivity of the data, because of the nearly universal single-incumbent positions involved, and because it is nearly impossible to mask data for such positions. Edison stated that the facts that Edison had already served on all parties a study of publicly available data on executive compensation from proxy statements and that Edison's executive compensation represents a small fraction (less than 0.5%) of total payroll expense mitigate this shortcoming.

In response to an ALJ request, Edison broke out figures comparing its nonexecutive positions to those comparator firms located in California and Southern California. Edison found its overall nonexecutive compensation level to be 1.1% below the California market and 0.8% above a limited number of comparator firms in the Southern California market. (Exhibit 163, p. 1.) Edison noted that this breakout resulted in a smaller total firm sample, especially in the physical employee category which had only two California firms and one in Southern California.

DRA

DRA recommended a $59 million reduction to Edison's revenue requirement for nonexecutive employee wages and benefits. This recommendation consists of two parts: (1) a $24 million reduction in cash compensation for wages 2.8% in excess of market and (2) a $35 million reduction to noncash compensation which includes PBOPs. DRA did not challenge Edison's executive compensation level because this makes up such a small percentage of total compensation.

The policy consideration underlying DRA's $24 million reduction, which it terms "market parity," is that it is not appropriate for the Commission to allow for an error factor in compensation surveys. DRA argued that an error factor routinely disadvantages the ratepayer because it alleviates the utility's need to demonstrate the reasonableness of its compensation level. DRA argued that an error factor for compensation surveys is no more appropriate than an error factor for a cost of capital forecast and that compensation at market rates is the only appropriate standard for Edison's compensation allowance. With respect to the $35 million recommended reduction, DRA argued that the prefunding of PBOPs is a benefit that is currently being funded by ratepayers and must be recognized in the valuation of any benefit package.

DRA also argued that it has not been given an appropriate level of access to the underlying assumptions and algorithms

supporting Edison's total compensation studies. DRA has been denied the opportunity to corroborate the results of Edison's total compensation studies. DRA asserted that a comprehensive review of Edison's compensation studies is not possible as long as comparator-specific data is masked and coded. DRA stated that PU Code § 583 protects the confidentiality of participating firms such that increased DRA access should be allowed.

Finally, DRA recommended that the Commission require Edison to fund the cost of a joint compensation study in future general rate cases. DRA believed that Commission-mandated workshops should be required as a prelude to the retention of a compensation consultant. DRA believed that a joint study is the only way to circumvent what it terms a "black box" syndrome whereby parties are unable to validate the underlying assumptions that relate to a total compensation study.

Intervenor Unions

The Intervenor Unions stated that Edison's showing is reasonable in light of a number of considerations, which include: (1) package bargaining, which allows collective bargaining agreements to be established based on the range of compromises and topics; (2) federal preemption, which precludes the government from becoming a party to collective bargaining negotiations; (3) wage dispersion in unregulated markets; and (4) statistical error in wage surveys.

The Intervenor Unions argued that the Commission would be intruding on the "give and take" inherent in the collective bargaining process if it chose to reduce Edison's revenue requirement for wages and benefits. The Intervenor Unions believe that wages are but one part of the bargaining process and the Commission would by default eliminate wages as a collective bargaining issue if it were to endorse the DRA's position of total compensation at market rates.

The Intervenor Unions also argued that federal preemption precludes the Commission from adopting the DRA's position. They believe that DRA's position would directly impact future negotiations and, as such, would make the Commission a government party to the collective bargaining process, which violates the principles set forth in <u>Golden State Transit Corporation v. City of Los Angeles</u>, 475 U.S. 608 (1986) (<u>Golden State</u>). The Intervenor Unions also argued that DRA's position is incorrect because a single market wage does not exist. Therefore, it is inappropriate to believe that wages could be set at a prevailing market level. The Intervenor Unions believe that DRA's position endorses zero wage dispersion, which is not consistent with wages in unregulated markets.

Lastly, the Intervenor Unions argued that DRA's position fails to take into consideration survey error. The Intervenor Unions believe that the sample selection methodology and sample size make DRA's position of compensation at market wages difficult if not impossible to realize and that DRA's position ignores inevitable survey bias.

<u>Settlement</u>

The settling parties agreed to Edison's requested compensation levels because the results of Edison's study were not statistically different to a significant degree from the market average, and were corroborated by comparisons to the California and Southern California markets.

At the settlement hearings, TURN proposed several reductions to Edison's employee compensation request. TURN proposed that the Commission reduce Edison's revenue requirement by $20 million to counteract the cost increases which TURN states have resulted from the growth in Edison's management ranks. TURN also advocated that the Commission reduce Edison's revenue requirement

by about $7.385 million to reflect the management wage freeze which Edison announced after it submitted the settlement to the Commission.

19.3 Discussion

19.3.1 Burden of Proof

Before addressing the merits of this issue, it is important to emphasize that the utility bears the burden to justify employee compensation levels, and that wages and salaries should be reasonable compared to the relevant market. As the Commission stated in a decision for PG&E's test year 1990 general rate case:

> "While we are disappointed in DRA's showing, we are even more disappointed in PG&E's showing on this issue in this proceeding. The burden of proof on the reasonableness of compensation is on the utility, not on the staff. We have tried to make it clear in D.83-12-068, D.86-12-095, and D.87-12-066, that we expect the utility to do more than simply critique DRA's efforts. We expect an affirmative presentation from the utility on the level of overall compensation and a comparison to similar compensation levels in the relevant job markets. In the absence of such a showing from the utility we are reluctant to apply any labor escalation factor to wage levels found reasonable in the previous general rate proceeding." (D.89-12-057, 34 CPUC2d 199, 279.)

Over at least the last eight years, the Commission has attempted to have the parties develop a record regarding employees' total compensation, not just wages and salaries. As the Commission has explained, "Since employees choose employment opportunities on a total compensation basis, we consider it reasonable to judge utility compensation in the same manner." (D.87-12-066, 26 CPUC2d 392, 457.)

The utility carries the burden of proving that its compensation levels are reasonable and cannot escape that burden by shifting it to DRA. (See e.g., D.91-12-076, 42 CPUC2d at 663.)

19.3.2 The Appropriate Revenue Requirement

In Edison's last general rate case, we stated we were "disturbed that we must again authorize labor expenses based on trends and averages of historical expenses, but the record evidence forces us to do so. We question whether labor expenses 2.88% higher than the market average are necessary for delivery of safe, reliable service at reasonable rates, but we reluctantly find that Edison's wage and salary levels are reasonable." (D.91-12-076, 42 CPUC2d at 663.) For Edison's next general rate case, we ordered Edison and DRA to continue their joint studies, with more emphasis on total compensation, total benefits as a percentage of cash compensation, and the distribution (not only averages) of total compensation among firms. (42 CPUC2d at 663 and 741, Finding of Fact 17.) We also ordered Edison to file or serve testimony on wages and salaries, with increased emphasis on total compensation, total benefits as a percentage of cash compensation, and the distribution of total compensation among comparable firms. (42 CPUC2d at 761, Ordering Paragraph 44(a).)

The discussion in Section 19.1 demonstrates the difficulties Edison and DRA have had in complying with our directive. In fact, because of these difficulties, we had to eliminate our directive to establish a joint database, and the ALJ had to address accessibility and confidentiality concerns in the ALJ Ruling. We agree with the ALJ Ruling that although neither Edison nor DRA is solely to blame, both are at fault in failing to resolve their difficulties in complying with D.91-12-076's directives. We are concerned that the fundamental issue of the reasonableness of Edison's showing has been clouded with DRA's and Edison's inability to agree on the appropriate level of data accessibility. Certainly that disagreement has clouded DRA's showing, which we determine to be poor. Nonetheless, our task is to determine whether, based on the existing record, Edison has met its burden of proof in establishing that its requested expenses are reasonable.

DRA spends much time criticizing what it terms Edison's "black box" showing because it was unable to verify data underlying the study. For instance, DRA is troubled by Edison providing masked data, since DRA cannot go back to the comparator firms and independently verify that they transmitted the correct information. DRA also states it could not verify Edison's job matching in that Edison did not maintain any workpapers, notes or other documentation in connection with the job matching process. DRA argues that because of the existence of the "black box," it did not follow through and verify other data which was verifiable based on the information provided by Edison or its consultant. Edison responds that it complied with the ALJ ruling, that DRA was trying to relitigate the ruling, and that DRA had ample time to verify Edison's data (in some cases from as early as August 1993). We agree that in instances where the ALJ ruling stated Edison could provide masked data, Edison was not required to provide anything more. However, in certain critical areas, we believe Edison did not provide the requisite underlying data in order for us to be comfortable with a determination that its compensation levels are reasonable.

For example, the one area Edison and DRA agree on is that job matching and benchmarking play a crucial role in determining total compensation. When conducted properly, the job matching process systematically compares job families within each firm to similar job families within comparator firms. Each position within a benchmarked job family is compared to similar positions at comparator firms until the sum of all positions matched is used to determine the average total compensation level for each firm.

In order for a total compensation study to be valid, it is critical that an accurate "apples to apples" comparison be made for each job match. If a given job family is under- or overmatched, then the validity of that job family as a contributor to the firm's total compensation level can be questioned. DRA

states that as much as 60% of a utility's total compensation costs can be attributed to cash compensation. How total cash compensation is measured relies on how completely the matching process is conducted. Edison emphasized the critical role job matching plays in the compensation analysis and that it conducted the job matching process with great care.

Unfortunately, Edison has not met its burden of proving that its job matching and benchmarking decisions are reasonable. We believe Edison should demonstrate that its job matching decisions and benchmarks, in addition to related data inputs, assumptions, and overall methodology, fully support its compensation level. Although Edison made workpapers associated with the development of its benefits and pension algorithms available to parties, Edison did not provide documentation for its job matching assumptions and benchmarking conclusions. For example, Edison stated that its job matching was conducted according to the American Compensation Association guidelines, and provided a copy of the guidelines. However, Edison did not provide any notes or other documentation regarding the job matching process (i.e., Edison did not provide factual evidence demonstrating it conducted the job matching process according to the guidelines). Edison did not demonstrate how Edison employees determined which positions from outside comparator firms "matched" Edison's benchmarked positions). We are genuinely concerned that an incomplete showing by Edison regarding its job matching and benchmarking decisions precludes independent analysis of Edison's total compensation showing.

Edison's Exhibit 55 poses an additional problem. Edison's job matches and benchmarks appear incomplete. Several illustrative examples are in order. The engineering job family, which represents approximately one third of the incumbents in the Professional/Technical analysis, is one example. The engineering job family begins with grade level #1 (Assistant Engineer), skips

several grade levels between grade level #1 and #7 (Engineer 1), and culminates with grade #9 (Senior Engineer 1 and Supervisory Engineer) positions. We are concerned that Edison's lower level engineering job matches (below grade #9) are incomplete because of the large gap between grade #7 and grade #1. We are disappointed that a benchmark (engineers) critical to Edison's compensation showing is so poorly developed or would lack workpapers to support Edison's job matching choices.

We are also troubled by Edison's showing in its Managerial/Supervisory Analysis. Edison provided incumbent data for seventy (we assume all) Supervisory Engineers (grade #9). However, Edison has not provided job match information for grade levels higher than the grade #9 supervisory position. It is reasonable to expect that the seventy grade #9 engineers and the Senior Engineer 1 (grade #9) position should report to higher level engineering positions. However, this is not evident in Edison's showing. Since there are several comparator firms that are also utilities in Edison's exhibit, we believe it reasonable to expect that the engineering job family would include a more comprehensive showing of several clear and distinct levels below and above the grade #9 positions.

Another example concerns the clerical benchmarks. The job matches for the secretarial job family also appear incomplete. The Secretary 4 and Administrative Secretary positions are matched. However, there is a gap of several grade levels between the Secretary 4 (grade D) and the Administrative Secretary (grade H). We find it unreasonable to assume that Edison would not have representative job matches for secretarial positions below or above the Secretary 4 position and secretarial/administrative job matches above the Administrative Secretary. Without appropriate documentation to verify Edison's job matching conclusions we must conclude that Edison's clerical position comparative analysis is also incomplete.

Page 8 of Edison's Exhibit 55 states:

"The standard compensation practice is to select a large enough sample of jobs to represent 10 to 20 percent of the total employee population. Edison's compensation surveys for this rate case include positions representing over 30 percent of Edison's employees."

Although this may be industry practice, it does not absolve Edison from meeting its burden of proof. We need to be satisfied that Edison has made a fair and unbiased selection of sample jobs rather than merely selecting 30 percent of its employees or including some positions in a job family but excluding other positions. Edison's showing is lacking since Edison has not provided documentation to support its job matching conclusions or workpapers to support its criteria for benchmark sampling.[92]

Although past decisions have not been satisfied with progress by Edison and other utilities' total compensation showing, we have had the benefit of looking forward to the next general rate case with the hope and expectation that the utility will do a better job. For example, in Edison's test year 1988 general rate case, we stated that:

"[o]ur objective is to ensure that ratepayers are not burdened with paying for employee

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92 Edison also presented a study conducted by the UCLA Statistical Consulting Center (Exhibit 55, Appendix B). Contrary to Edison's assertion, the UCLA study does not provide independent support for Edison's position because the study defers to Edison's judgment on the adequacy of its job matching exclusions (Exhibit 55, Appendix B at p. B-2 item 5.). The UCLA study does not establish that Edison's compensation study did not systematically exclude critical job matches. As the UCLA study states, "Some jobs are excluded for various reasons. This is valid if the reasons are not systematically related to discrepancies between Edison's compensation and market compensation." Since Edison has not shown that its job matching conclusions (or exclusions) are based on an unbiased sample, we cannot conclude that the UCLA study supports the reasonableness of Edison's compensation showing.

> compensation levels beyond that which is necessary for Edison to provide safe reliable service at reasonable rates. This type of evaluation is difficult because of the subjectiveness involved in quantifying the variables used. To minimize this, we expect both PSD (predecessor to DRA) and Edison in future general rate proceedings to develop an agreed upon data base for judging the reasonableness of employee compensation levels. For this proceeding, we find Edison's justification for its APS compensation levels reasonable." (D.87-12-066, 26 CPUC2d 392, 457.)

Similarly, we stated in Edison's last general rate case that "[w]e are disturbed that we must again authorize labor expenses based on trends and averages of historical expenses, but the record evidence forces us to do so. ... [W]e reluctantly find that Edison's wage and salary levels are reasonable." (D.91-12-076, 42 CPUC2d at 663.) We then gave Edison and DRA instructions on how to approach this issue in the next general rate case. (42 CPUC2d at 663, 741 (Finding of Fact 17) and 761 (Ordering Paragraph 44(a)).) (See also PG&E's test year 1990 general rate case, D.89-12-057, 34 CPUC2d at 279: "While we are disappointed in DRA's showing, we are even more disappointed in PG&E's showing. ...") We expect this to be Edison's last general rate case. Consequently, we can no longer rely on Edison's testimony in its next general rate case to rectify the problems we note here. Edison's failure of proof on this critical issue calls into question whether this decision can provide a reliable starting revenue requirement for PBR.

The record did not produce a reasonable numerical figure for Edison's total compensation budget. For purposes of this proceeding, we utilize the results of Edison's showing on total compensation. Although it can be shown that Edison's compensation showing is not statistically different from market compensation, this result depends on unbiased estimates, a finding we cannot make

based on the record before us. As such, the compensation level we authorize today is for the limited purpose of test year 1995 and is not necessarily the funding level which should serve as the basis for PBR. If and when we revisit this issue in a future general rate case or PBR proceeding, we will require Edison to present a study in which independent experts have undertaken all analysis with regard to benchmarks, job matching, and the selection of comparable firms. Alternatively, DRA may sponsor such a study. Without such independent analysis, we will not consider Edison to have met its burden to demonstrate the reasonableness of its employee compensation.[93]

We reject DRA's proposed $24 million reduction because this proposal only addresses cash compensation. As we stated in Edison's last general rate case, "DRA does not fairly compare all of the elements of employee compensation, and we do not know where the 2.88% differential [the percentage DRA claimed Edison's wages and salaries exceeded market] and employee benefits place Edison in relation to comparable firms." (D.91-12-076, 42 CPUC2d at 663.)

We also reject DRA's recommended reduction to noncash compensation for PBOPs. DRA's recommended disallowance is based on two bar graphs generated by Towers Perrin for the SoCalGas test year 1994 general rate case. The first bar graph identified the

93 As stated above, we do not decide in this decision whether, in general, the revenue requirement we establish in this decision should serve as the baseline for PBR.

comparator companies, but the second did not. DRA notes that the Edison figure was placed to the left of the SoCalGas figure in the first bar graph, and therefore assumes that the unidentified bar to the left of SoCalGas in the second bar graph also represents Edison. DRA concludes that for the year 1992, Edison is shown as one of the companies that was 12.5% to 24.5% above market. In this case, although we find that Edison has not met its burden of proof with respect to the reasonableness of its total compensation request, we have made a reduction above. We find DRA's evidence regarding PBOPs speculative as applied to Edison, and therefore deny DRA's recommended disallowance for PBOPs.[93]

We do not agree with the Intervenor Unions that we are preempted from reviewing and making any adjustment to Edison's compensation request. In PG&E's test year 1993 general rate case, we addressed the issue of whether the Commission was preempted from examining the level of a utility's compensation for ratemaking purposes. We determined that we are not preempted from such examination, citing Southwestern Bell Telephone Company v. Arkansas Public Service Commission, 824 F.2d 672 (8th Cir. 1987) (Southwestern Bell). (See D.92-12-057, 47 CPUC2d 143, 175-175.) We stated that Southwestern Bell rejected the union's preemption argument that the National Labor Relations Act (NRLA) prevents a public utilities commission from adjusting to recover in rates only a portion of the wages and benefits that are the product of collective bargaining.

> "The Arkansas Commission is charged with the responsibility of setting rates that state telephone users will pay and determining a fair rate of return that [the utility] may earn. As part of this process, the Commission assesses the Company's expenses to determine whether they are reasonable. If the Commission finds that they are not reasonable, an issue controlled by state law standards of arbitrariness and capriciousness, then the Commission will not pass them on to consumers in the form of rate increases. We conclude

> that the Commission's action disallowing recovery of certain nonmanagement wage and benefit expenses does not rise to the level of an impermissible intrusion into or control over the relationship between the Company and [the union]. We finally observe, as did the Ninth and First Circuits, that in any regulated industry, myriad governmental decisions, from ratesetting to the imposition of safety standards, undoubtedly will affect labor relations. Any indirect effect of the ratesetting action taken in this case, however, falls short of the kind of state interference with the labor-management relationship that Congress intended to proscribe." (Southwestern Bell, 824 F.2d at 676.)

The Intervenor Unions cite Golden State in support of their preemption argument. In that case, the City of Los Angeles decided to reject the renewal of a taxicab franchise but agreed to reconsider the application in a week if the drivers' strike was settled. The court held that the city had interfered with the collective bargaining process by imposing a positive durational limit on the strike. The Intervenor Unions argue that adoption of DRA's proposal would threaten Edison with a penalty if it agreed to wages the Commission subsequently found to be excessive. Such a penalty would impact the negotiating process in several ways, all of which, in the Intervenor Unions' opinion, would offend federal labor policy. The Intervenor Unions distinguished Southwestern Bell by noting that the Arkansas Commission allowed a ten percent leeway above average, that the case is not precedential in this circuit, and that the court's reasoning seems flawed.

We disagree. First, we do not reduce Edison's requested employee compensation based on DRA's "market parity" proposal. Second, Southwestern Bell distinguished the Golden State case, and we find this reasoning applicable to this case as well.

> "These operative facts [of Golden State] are clearly distinguishable from the facts in this case. Here, the Commission has the authority under Arkansas law to establish intrastate telephone rates. This is not disputed, nor is the Commission's authority to consider the reasonableness of claimed expenses in the ratemaking process. The problem, according to [the utility], is that this authority to set rates and protect the interests of the ratepaying public infringes on the duty under the NLRA of both the Company and [the union] to bargain in good faith.
>
> "We cannot agree. Nothing in the Commission's order encroaches upon either party's ability to use economic pressure in future negotiations to gain concessions from the other. The Company remains free to resist the union's demands, and [the union] may authorize a strike if its terms are not met. Furthermore, the Commission has not vetoed the wage agreement. As we have already pointed out, the Company stipulated that notwithstanding the Commission's order, it is obligated to pay the bargained-for wages. Finally, nothing in the NLRA guarantees that wages agreed upon in collective bargaining will be recovered from consumers, whether the business is regulated or not." (Southwestern Bell, 824 F.2d at 675.)

We also deny TURN's proposed reduction with respect to growth in management ranks. TURN alleges that over the last ten years, Edison's management employees' hours have grown significantly faster than the number of hours for Edison's nonmanagement employees over the same period. TURN proposes to reduce Edison's revenue requirement by $20 million to counteract the cost increases which TURN states are due to the growth in Edison's management ranks. Edison complains that this testimony is similar to that which TURN proposed in Edison's PBR proceeding and also disputes that TURN's adjustment should be made.

We do not pass judgment on whether TURN's proposal should be adopted in the PBR proceeding, because the full record is not

before us here. Our discussion is limited to how TURN's proposal should affect this proceeding. Here, TURN has not demonstrated why it is appropriate to use 1985 as the baseline year to determine if Edison has the appropriate level of managers. Also implicit in TURN's argument that Edison is top-heavy with managers is that there are too few nonmanagement employees as compared with 1985. However, TURN's analysis holds Edison's nonmanagement hours constant from the 1992 level. (Exhibit 763, Appendix D.) TURN's recommendation is thus based on more than the allegation that the management/nonmanagement ratio has grown too high; it also presumes that the total workforce is too big. For a workforce of a given size, if there are too many managers to begin with, the company should employ more nonmanagers -- not the same number -- after paring down the management level. Yet, TURN did not make a case as to why it believes Edison's workforce is too large.

TURN also recommends that Edison's revenue requirement should be reduced by about $7.385 million to reflect the management wage freeze which Edison announced after it submitted its settlement to the Commission.[94] Edison opposes this reduction on

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94 TURN's witness Mr. Marcus calculated the proposed reduction as follows. Edison did not challenge these calculations, although it opposed TURN's proposed reduction for the reasons set forth in the text.

TURN states that according to Edison's own figures, 49% of Edison's salaries were paid to management and administrative employees. The settlement's forecast labor escalation rate for all employees is 2.63%. Recalculating the rate to reflect its limited application under the wage and salary freeze, TURN calculated $7,385,000 in salary savings and a resultant reduction of FICA payroll taxes of $295,000. TURN also states that, in addition, since about 26% of wages and benefits are capitalized, flowing the freeze through the capitalized portion reduces end-of-year plant-in-service by $2,595,000 for direct labor and another $104,000 in

(Footnote continues on next page)

several grounds. It states that the wage and salary freeze which TURN cites is part of a broader 1995 Results Sharing program under which performance targets have been set for management and administrative employees at both the overall company and business unit levels, and that none of the approximately 7,000 Edison employees represented by bargaining units are now subject to the program. Edison also states that instead of a base pay increase, these employees will receive incentive compensation based on their success in meeting cost containment targets; Edison's action is not an indefinite salary freeze but rather a different form of compensation. Edison also states that its Results Sharing program is consistent with its general rate case testimony on which the settlement was based. In this testimony, Edison testified that its future compensation strategy would place more emphasis on paying for performance instead of the more traditional approach towards increasing employee base pay. Edison argues that the Results Sharing program is absolutely essential for Edison to meet its PBR target.

In PG&E's test year 1987 general rate case,[94] even though we noted that PG&E's executive compensation (including its proposed incentive plan) is commensurate with levels paid by utilities of comparable size, we concluded that a 50/50 sharing of the cost of its incentive plan was reasonable, stating that we find merit in the staff argument that if PG&E's executives perform well enough to

(Footnote continued from previous page)
payroll taxes. The mid-year plant-in-service is reduced by $1,349,000.

justify the bonus, then there should be enough savings to pay for the incentive plan. (D.86-12-095, 23 CPUC2d 149, 187.) We think a similar approach is appropriate here. We also find merit in TURN's argument that including in rates the full amount of Results Sharing program gives the utility a poor incentive, since it makes the utility indifferent to whether it achieves the productivity gains. For instance, if the utility meets its productivity goals, it shares the incentive funds with its employees. If it does not meet its productivity goals, the utility has already collected rates based upon the incentive funds which it now does not have to pay its employees. In this case, since both shareholders and ratepayers could benefit from increased productivity, we approve 50% of TURN's recommended reduction. We appropriately adjust the labor escalation rate for 1995 to reflect this reduction. (See Appendix D.)

20. Capitalized Software

20.1 Introduction

D.92-11-051 (which grew out of Edison's last general rate case) found that capitalizing Application Software Development Costs (ASDC) significantly benefits ratepayers, principally due to the upfront flow-through of income tax deductions and promotion of equity by matching cost recovery of the application software assets over their expected lives. Pursuant to that decision, Edison now capitalizes software projects which exceed $100,000 and have a useful life of at least five years.

Edison's O&M expense recommendation reflected about $13 million in capitalized software savings. DRA disputed this figure, alleging that Edison (1) excluded from its calculation two important categories of software savings and (2) failed to normalize (average) projected savings for 1995-1997. Based on these conceptual divergences, DRA originally calculated that Edison's software savings estimate fell short by $23.7 million. In its reply brief, DRA acceded to Edison's argument that DRA's

estimate double-counted pre-1993 savings already recovered in rates, and accordingly slightly lowered their estimate of the savings shortfall to $21.0 million. We now address the issues raised by DRA with respect to the software savings categories, and its proposal to normalize savings over the rate case cycle.

20.2 Software Savings Categories

20.2.1 Positions of Parties

Prior to Settlement

Edison presented the following ratepayer benefits flowing from its current array of approximately fifty capitalized software projects: (1) avoided fuel costs, (2) avoided capital costs, (3) cost reductions, (4) cost avoidances, and (5) productivity/other. Edison commented that "avoided fuel costs" are the subject of ECAC proceedings, and "avoided capital costs" are by definition unrelated to O&M expense reductions. Edison distinguished "cost reductions" from "cost avoidances." The former involve expense reductions associated with a fixed activity level; the latter encompass situations where activity levels rise with no concomitant increase in costs (thereby avoiding future budgetary growth). Edison reserved the term "productivity/other" for productivity upgrades of a more qualitative nature (e.g., improved morale, production of higher-quality information, etc.)

DRA and Edison agreed that avoided fuel costs and avoided capital costs lie outside the scope of GRC O&M expense adjustments. Edison's $13 million savings adjustment consisted solely of the sum of the cost reductions which it identified for its capitalized software projects. The dispute was over DRA's proposal to add the dollar benefits which Edison included under the categories "cost avoidance" and "productivity/other" to Edison's $13.0 million cost reduction total.

DRA reasoned that any "cost avoidance" really consists of two logically separable adjustments: a cost reduction, and an offsetting cost increase. Edison therefore should have demonstrated

how cost savings realized by capitalized software cost avoidances are absorbed by increased workloads. By way of illustration, DRA noted that Edison's description of the Steam Work Management System (WMS) does not specifically indicate why this program merely avoids, rather than directly reduces, costs by $3.158 million. Pointing to additional instances where Edison allegedly mistook cost reductions for cost avoidances, DRA argued that Edison systematically confused the two categories. DRA therefore treated all avoidance savings as cost reductions in its O&M expense recommendation. Finally, despite the nominally amorphous character of the category "productivity/other," DRA argued that ratepayers should reap whatever savings Edison did succeed in quantifying. For example, since Edison calculated $2.205 million in savings for the SONGS INDAMS software program, DRA asserted that this amount should not have been swept under a subjective classification.

Edison criticized DRA for waiting until its opening brief to clarify its initially sketchy position on capitalized software, for the speculative nature of its recommendation, and for missing the point that time freed up from many software programs can be utilized to meet the growing workload stemming from an increase in customers which even DRA forecasted would occur. Furthermore, the amount of time saved per employee per week may in some cases be too small to yield feasible cost reductions, unless employers were to have unlimited flexibility to hire or lay off workers on an hours-per-week basis. Edison claimed that DRA's critique of the WMS program was procedurally unfair -- since DRA did not cross-examine Edison's witness and expressed no disapproval of that program prior to briefing -- and contradicted DRA's concurrence with Edison's overall Steam O&M estimate. Edison also opposed DRA's treatment of "productivity/other" savings as cost reductions, maintaining that they do not reduce the required level of O&M. For example, the INDAMS program just offsets anticipated real growth in nuclear industry costs. Edison further alleged that DRA's capitalized

software proposal "ignores the evidence" of its own productivity witness "that an appropriate amount of productivity is already reflected in our estimates."

<u>Settlement</u>

Edison agreed that the $3.158 million Steam WMS savings should be reclassified as a cost reduction. The settling parties did not make any other adjustments to Edison's capitalized software savings estimate.

<u>20.2.2 Discussion</u>

The testimony of DRA's steam and productivity witnesses has nothing to do with DRA's stance on capitalized software. This issue was expressly treated separately by DRA; for this reason DRA's recommended disallowance was presented as a stand-alone line item in its Results of Operations summary (e.g., Exhibit 402, Table 14).

Despite the thinness of their overall showing, DRA's crisp decomposition of a cost avoidance into offsetting cost reductions and increases has merit. To satisfy its burden of proof, Edison should have provided the justification for classifying each project's cost savings as merely an avoidance of future budgetary growth, rather than a direct reduction to test year O&M. That is to say, for a given software program, Edison should either describe the rising activity level which characterizes the avoidance, or show how the work assignments in the appropriate sector of the company are of such an indivisible nature as to force the idled hours to be paid even though no longer needed. Absent such a demonstration, ratepayers deserve the benefit of the doubt as to whether such productivity gains do in fact reduce current costs.

Edison's rebuttal testimony included a "cross-reference" table listing the supporting documentation for each of its capitalized software projects. The first cost avoidance on the list is the Steam WMS project discussed above for $3.158 million.

Our review of the Company's description of this project forces us to agree with DRA's conclusion that a 6.25% productivity improvement spread over 1,634 employees is a straightforward cost reduction.

The next significant cost avoidance on the list is the Steam ISIS project ($1.440 million). Edison's description of the benefits of this project is strikingly similar to its discussion of the Steam WMS project: reductions in overtime and contractor utilization, reductions in time required to perform standard tasks, reductions in equipment service time, and improved unit reliability. The only significant difference between Edison's descriptions of these two projects is that the WMS project will apparently substantially decrease paperwork, while ISIS will prevent a significant increase in paperwork. No explanation is given for the rise in paperwork in the absence of ISIS, let alone to what extent it would absorb the stated savings. We will therefore reclassify 1/2 of the ISIS "cost avoidance" as a cost reduction.

In reviewing the remaining projects on the list, we found several additional cost avoidances which, due to Edison's failure to adequately document them as such, we will treat similarly as cost reductions for ratemaking purposes: Power Supply PLAS ($0.669 million); Human Resources Training Records ($0.246 million); Power Contracts-POCIS ($0.445 million); RD&D LAN MIS ($1.406 million); and Info Tech Workflow Tracking ($0.152 million).

In sum, beyond the $3.158 million associated with the Steam WMS, we have reclassified 1/2 of an additional $4.358 million in cost avoidances as cost reductions to be included as O&M software savings for test year 1995.

Finally, Edison fails to provide a persuasive basis for excluding the productivity/other estimate from the O&M savings total. For example, Edison's observation that INDAMS offsets real growth in nuclear industry costs effectively argues that

really a cost avoidance (based on generally rising industry-wide costs rather than on Edison-specific activity levels) and thus misses DRA's point: to the extent Edison has succeeded in quantifying productivity improvements, ratepayers should benefit. Another example may be found in the SSID Meter Test Support System, for which the Company calculated $0.540 million in productivity savings. (A.90-12-018, SCE-38, Page 214.) We will roll into the total O&M software savings 1/2 of all quantified benefits associated with the "productivity/other" category. Upon subtracting pre-1993 savings to avoid double-counting, this amount totals $1.415 million.

20.3 Software Savings Normalization

20.3.1 Positions of Parties

Prior to Settlement

DRA advocated averaging capitalized software savings over the rate case cycle, in order that ratepayers may take advantage of the rising tide of forecast software savings over 1995-1997. DRA pointed to PG&E's test year 1990 general rate case, as well as Edison's own proposal in this case to normalize Customer Service Automated Systems over 1995-1997. DRA disagreed with Edison's objection that such averaging is unfair absent a comparable normalization of costs, which Edison said would be understated until the next general rate case due to the exclusion of intangible assets from the attrition formula. DRA responded that a utility has the flexibility to spend its pool of capital attrition dollars on substitute projects; thus Edison need not undercollect for capitalized software programs.

Edison viewed DRA's stance to be ironic given its attrition recommendation in this case. According to Edison, the normalization proposal from PG&E's 1990 general rate case which DRA's witness cited at the hearing actually recommended an averaging process which did not extend beyond the test year, and the PG&E 1990 general rate case decision also denied a separate DRA

proposal to normalize Account 931 expenses over the rate case cycle. Edison's recommendation regarding customer service software was an exceptional case stemming from the decommissioning of systems slated for replacement. Edison argued that DRA's discussion of capital expenditure flexibility in attrition years ignores the potential for overspending as well as underspending its funding authorization. Edison noted that DRA has failed to substantiate its claim that Edison omitted software project tax benefits from its attrition request.

Settlement

The Settlement did not perform a normalization adjustment to capitalized software savings.

20.3.2 Discussion

In setting a test year revenue requirement under the Rate Case Plan, we generally do not look beyond the test year. Unless compelling reasons can be advanced for so doing (and the example of Edison's customer sevice systems software development from Exhibit 28 appears to be such a case), DRA's recommendation is results-oriented and unfair to Edison, who would not receive comparable normalization of the costs of providing these ratepayer benefits. Utility capital funds are indeed substitutable, but if our test year forecast is unbiased, the utility is just as likely to suffer a funding shortfall as it is to realize a windfall.

20.4 Reasonableness Review and Quarterly Reports

We reject as unnecessarily burdensome DRA's proposals for reasonableness reviews for capitalized software projects and quarterly progress reports for the SCEnet project.

20.5 Summary

In lieu of DRA's recommended $21.0 million O&M expense reduction for capitalized software benefits, we adopt a reduction of $6.757 million, the sum of Edison's Test Year 1995 estimates for the Steam WMS cost avoidance ($3.158 million) and 1/2 of the additional unsupported cost avoidances ($4.358 million) and

"productivity/other projects ($2.839 million) identified in Section 20.2.

21. Attrition

21.1 Positions of the Parties

Prior to the Settlement

In its application, Edison requested increases in operational attrition of $121 million in 1996 and $111.2 million in 1997. After the evidentiary hearings, Edison revised its request to a $92.1 million increase in 1996 and a $96.8 million increase in 1997. DRA recommended that attrition increases in 1996 and 1997 should not be granted unless the annual inflation rate exceeds 6%. If the annual inflation rate exceeds 6%, DRA recommended that Edison should be authorized to file for an attrition increase based on the annual inflation rate minus 6%. The Farm Bureau supported DRA's proposal.

DRA stated that the Commission initially adopted the attrition mechanism in the early 1980s as a direct consequence of double-digit inflation and double-digit returns on short- and long-term debt during the 1980s. DRA argued that the attrition mechanism should be significantly modified in response to current economic conditions such as the current weak economy, slow economic growth, and low inflation rates. Since the current attrition mechanism consists of formula-driven computation handled by an advice letter, it is possible that a utility will be granted a larger revenue requirement increase by its attrition filings than by its general rate case proceeding. In fact, DRA pointed out that Edison's requested attrition increase for 1996 exceeds its request for test year 1995 and argues that the current attrition mechanism does not provide an incentive for Edison to manage cost escalation.

Edison opposed DRA's attrition proposal. Edison also made its own proposal that the Commission adopt tariff language describing the methodology used to calculate the attrition year rate adjustment. Edison maintained that the Commission should keep

the current attrition mechanism until PBR is approved and effective, arguing that it is not the time to modify the existing attrition method while the Commission is considering extensive recommendations for changes in the electric industry restructure.

Edison stated that DRA's attrition proposal, if adopted, would impair Edison's ability to earn a fair rate of return for its shareholders, since the current attrition mechanism compensates the utility for increasing costs due to inflation and customer growth. Edison also maintained that lower inflation does not eliminate the need for an attrition year adjustment, and projects that the company's escalation rates will average 3.3% in 1996 and 1997 without inclusion of health care and 3.8% with health care. Although customer growth is not expected to be as high as in the mid-1980s, it is still, according to Edison, substantial. Edison projected its customer growth for 1996 and 1997 to be 1.76% and 1.9% respectively.

Both Edison and DRA agreed that if the Commission approves Edison's PBR proposal, the issue of attrition is moot in the general rate case.

DRA opposed Edison's request regarding tariff language, arguing that it provides a negative incentive to Edison at a time when its rates are higher than those charged on average by all other utilities across the United States.

The Settlement

The settling parties agreed that if Edison's PBR application results in the authorization of PBR transmission and distribution and generation mechanisms to be effective on and after January 1, 1996, Edison will not request attrition increases during the period when these mechanisms are in effect. However, Edison and DRA, promptly after learning that these mechanisms will not be in place by January 1, 1996, would ask the Commission to issue a decision on the attrition issue based upon the existing record or some other attrition mechanism if mutually agreed to by Edison and

DRA. The Farm Bureau opposed the settlement. Also, prior to the settlement hearings, Edison announced a rate freeze proposal.[95]

21.2 Discussion

The attrition mechanism originated in SoCalGas' 1981 general rate case, D.92497, 4 CPUC2d 725, 770 (1980). The mechanism was designed to protect the utility from extraordinarily high inflation rates and unpredictable changes in financial markets which might jeopardize the utility's opportunity to earn its authorized rate of return. Edison was first granted attrition in its test year 1981 general rate case, D.92549, 5 CPUC2d 39, 80 (1980).

In D.85-12-076, 19 CPUC2d 453, the Commission reconsidered the attrition mechanism and declined to eliminate it at that time, even though the Commission found that the attrition mechanism may provide "a disincentive to manage cost escalation and seek cost efficiencies." (19 CPUC2d at 466.) The Commission found that "current economic conditions undermine the need for an attrition adjustment mechanism but that a three year rate cycle with but one year of rate relief would not give the utilities a reasonable opportunity to achieve their authorized rates of return." (Id. at 456.) If the rate case cycle had not been extended to three years, the Commission stated it would have been inclined to abolish or declare a moratorium on the attrition allowance.

Edison argues that the economic conditions which motivated the Commission to maintain the attrition adjustment in

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95 "Edison Announces Price Freeze for Homes and Small Businesses, Sets Five-Year 25% Price Reduction Goal, Unveils New Price Options," released March 28, 1995 by Edison. In this press release, Edison indicated its intention to file an application or advice letter requesting Commission approval of its rate freeze implementation plans within 90 days. (See also D.95-05-016, slip op. at 4.)

1985 have not improved, i.e., inflation rates have not fallen since 1985. Our discussion addressing this same argument in SoCalGas' test year 1994 general rate case, D.93-12-043, slip op at pp. 25-26, is equally applicable here:

> "However, our reference to economic conditions in that order [D.85-12-076] was not necessarily limited to inflation rates. Conditions have changed since 1985 in ways that require us to reconsider the viability of the attrition year adjustment.
>
> "The state's economy, historically thriving and diverse, has changed considerably since 1985. Between mid-1991 and the end of 1992, California lost hundreds and thousands of jobs. Many thousands of workers are unemployed or underemployed. Businesses, large and small, are failing or unable to earn profits which reflect business risk. ...
>
> "The state's depressed economy is no longer volatile as it was during the late 1970s and early 1980s. Inflation rates have been and are expected to be low. Financial markets have been stable for several years. The economic circumstances which motivated the Commission to adopt attrition year adjustments in 1981 no longer exist."

Furthermore, we recognize that Edison's rates are high, well above the national average, and these high rates exist during a period of increasing competitive pressures in Edison's markets. In fact, Edison itself has recognized the need to decrease rates by announcing its rate reduction goal. A goal of our electric industry restructuring proceeding is to decrease rates. In SoCalGas' test year 1994 general rate case, we recognized that times change and regulation must accommodate those changes.

> "Under the circumstances, we would be abrogating our duty to the public if we granted large rate increases without a showing of need knowing that those increases would likely promote system bypass and subsequent rate increases. Some rate increases cannot be easily avoided. Automatic attrition year increases, however,

> The attrition mechanism is not an entitlement. Nor is it a method of insulating the company from the economic pressures which all businesses experience. (D.93-12-043, slip op. at p. 26.)

We seriously question a regulatory program that requires a year-long review (in this case, longer) of an approximate $62 million dollar rate increase request but no review for rate increases in the subsequent two years totalling a little under $200 million. Although this effect may occur because the utility is allowed to retain productivity gains in the attrition years and not in the test years, the utility would also be permitted to retain the productivity gains without an attrition year adjustment.[96]

It does not make sense to authorize an automatic attrition increase here while at the same time to consider implementation of Edison's rate reduction proposal in a different forum. If Edison believes that extraordinary circumstances arise which require rate increases before a form of PBR is implemented, Edison can file an application (not an advice letter) to make this request with specificity and to state how the request is compatible with its other requests and our other pending proceedings.

Edison cites the pendency of its PBR application and the Commission's proceeding concerning electric industry restructuring as reasons to maintain the current attrition mechanism (i.e. the status quo) until these proceedings are resolved. We disagree.

We have previously stressed the importance of a comprehensive evaluation of Edison's current operations and revenues in this general rate case so we can have a credible

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96 The Commission originally intended that normal productivity gains and the costs of customer growth would generally offset each other, and that the utility would be rewarded by extraordinary productivity gains in between general rate case proceedings.

benchmark if we choose to utilize it in the future.[97] Here, as stated above, our evaluation is generally circumscribed by the issues raised by the parties. Nevertheless, permitting subsequent large attrition increases to occur through the minimal review of an advice letter prior to our completed review of Edison's PBR application could skew this benchmark.

Moreover, we note that Edison's proposal in its PBR appears, at least in part, a proposal for a different type of attrition mechanism. Therefore, the result we reach today is interim, until this issue is addressed again in Edison's PBR application.

We also note that the principal reason articulated by the Commission in 1985 to maintain the attrition year adjustment was so that the utility could get rate relief before the next three-year rate cycle. We anticipate that Edison's PBR application will be well underway before Edison's three-year rate cycle ends. Furthermore, Edison has the opportunity to request a rate increase consistent with the limitations set forth above.

Finally, we do not believe that our decision deprives Edison of an opportunity to earn its authorized rate of return for the reasons stated above, and because of the opportunity to improve productivity and to reconsider priorities. Neither the constitution nor case law has ever required automatic rate increases between general rate case applications. Attrition year adjustments are a relatively recent innovation and they are more recent than the cases cited to by Edison in support of maintaining the current attrition mechanism. (See Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944); Bluefield Water

97 As stated above, parties to Edison's PBR proceeding question using the revenue requirement set by this case as the basis for PBR. This issue is raised in the PBR proceeding, not this case, and we do not decide it here.

Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).)

Several attrition issues have arisen regarding Edison's DSM funding requests. We address those issues in the section of this decision addressing DSM.

22. Resource Planning Analysis

Edison presented a resource planning analysis[98] to support funding requests for its 1995 general rate case. According to Edison, this resource planning analysis, among other things, supports its position that the continued operation of its gas-fired generation units is cost-effective. TURN did not believe the record in this proceeding supports Edison's conclusions of cost-effectiveness.

However, TURN noted that since the issue of the cost-effectiveness of Edison's gas-fired units has not been raised in this proceeding, it was unnecessary for the Commission to render an advisory opinion on this issue, which might be a controverted issue in other proceedings before the Commission. Edison stated that it offered the cost-effectiveness testimony solely to support its funding requests for capital and O&M expenditures for continued operation of Edison's gas-fueled generating units through the 1995 general rate case cycle.

We make the appropriate determinations for expenditures in various sections of this decision. We agree with TURN that because the issue of the cost-effectiveness of Edison's continued operation of its gas-fired units has not been raised in this proceeding, it is unnecessary for us to make a finding on this cost-effectiveness issue.

98 This section does not address any resource planning analysis Edison may have used to support the Phase 3 portion of the settlement.

23. Summary of Earnings and Related Issues

23.1 General Issues

This section addresses escalation rates, present rate revenues, net-to-gross multiplier, and jurisdictional allocation factors. At the evidentiary hearings, Edison and DRA disputed the labor escalation rate, but agreed to the appropriate rate in the Update testimony. (See Exhibit 169.) Other numerical differences between Edison and DRA in this section are attributable to differences in O&M expenses, capital, or other estimates which are addressed elsewhere in this decision. Therefore, there are no issues for us to address in this section.

23.2 Western Mobilehome Parkowners Association's (WMA) Distribution Plant Issues

WMA stated that Edison's proposed 1995 distribution plant costs are overstated or unreasonably high and offered two proposals. First, WMA compared Edison's allocated 1995 system average plant cost for Account 370 for domestic customers ($65.04) to the direct assignment of plant costs for domestic customers in mobilehome parks directly served by Edison ($31.42). WMA stated that because of the discrepancy between average costs of meters for domestic customers and mobilehome park customers, the Commission should consider reducing Edison's domestic meter plant-in-service forecast of $235,627,000 to reflect the level of cost savings that Edison has managed to achieve in serving mobilehome parks. WMA did not propose a specific monetary deduction here.

Second, WMA proposed that the Commission freeze the distribution plant costs for all other customers at 1992 levels since it was able to freeze the distribution plant costs associated with mobilehome park customers.

As to WMA's first proposal, Edison stated that the average domestic meter expenditure of $65.04 is not comparable to the mobilehome park meter expenditure of $31.42. Edison explained that the domestic meter cost is derived by allocating total company

average meter plant cost to Edison's domestic customers. Total company system meter costs include plant expenditures of all installed meters considered used and useful including more expensive industrial, commercial, and agricultural meters. Edison argued that when a direct assignment of costs is not applicable, costing principles allow cost allocation on the basis of overall ratios of the costs that have been directly assigned, or by a series of allocators that best reflect cost causation principles.

As to WMA's second proposal, Edison stated that the increases in distribution plant balances from 1992 to 1995 were for all distribution-related plant, including substations, primary facilities, and secondary facilities. Also about one-half of this amount is related to new service and about ten percent is related to substation expenditures, maintenance, conversions from overhead to underground facilities, and storm repair and other categories of expenditures. Edison stated the DMS-2 mobilehome park distribution facilities are for the most part related to the distribution secondary system.

We find Edison has sufficiently justified its requests with respect to WMA's proposals and do not adopt WMA's proposals.

24. Oral Argument and Comments on the Proposed Decision

Pursuant to PU Code § 311 and our Rules of Practice and Procedure, the Proposed Decision of ALJ Econome was published on September 14, 1995. Parties then had an opportunity to file comments and replies.[99]

On October 18, 1995, the full Commission held oral argument in this case pursuant to a request from Edison. Parties participating in the oral argument included Edison, CAL-SLA, CEC,

99 We received comments or reply comments from Edison, Cal/Neva, CAL-SLA, CEC, CBERT, CLECA, CMA, DRA, DGS, Farm Bureau, Intervenor Unions, IU, Trade and Commerce Agency, NRDC, SDG&E, SoCalGas, TURN, and UC.

IEP, Intervenor Unions, ICA, IU, NRDC, SDG&E, SoCalGas, Trade and Commerce Agency, TURN, and UC.

While we affirm the Proposed Decision in some respects, we have made the changes discussed below. We have also made other changes to the Proposed Decision to improve the discussion, add references to the record, and correct typographical errors.

We approve the conceptual framework offered by Edison and SDG&E, that subject to certain modifications would allow us to resolve Phase 3 issues. We also modify the Proposed Decision with respect to total compensation. (See Section 19.)

We modify the DSM section of the Proposed Decision to add approximately $5 million. (See Section 11.) We also modify the Proposed Decision's RD&D discussion and authorize an approximate $3.6 million addition: approximately $2.6 million for the Advanced Generation Program and $1 million a year for CIEE. (See Section 15.)

We modify the Economic Development portion of the Proposed Decision (Section 12.1) to add approximately $2.9 million.

We modify the Worker's Compensation of the Proposed Decision (Section 13.6.4) to add approximately $500,000.

We modify the Software Savings portion of the Proposed Decision (Section 20.2.2) to add approximately $3.8 million.

We add a discussion to the Proposed Decision discussing the termination of Edison's memorandum account which was used to track mechanically switched capacitor costs at Table Mountain. This discussion was inadvertently omitted in the Proposed Decision. (See Section 8.2.)

We also modify the Proposed Decision's health care discussion and adopt higher HMO trend rates for 1993 and 1994. (See Section 14.)

We also make the ALBRR we adopt today prospective from January 20, 1996.

We have also corrected two algebraic errors in the appendix tables attached to the Proposed Decision. First, our adopted reduction stemming from Edison's management/administrative employee wage freeze (Appendix D, Page 30) was understated, causing total base rates to be approximately $1.1 million too high. Second, the revenue requirement associated with return on rate base (Appendix B, Page 3) was approximately $700,000 too low.

We have modified Section 9.9.2 in response to Edison's comments to Commissioner Fessler's alternate to set an earlier date for Edison to demonstrate that all components of the program's revenue requirement will be borne only by participating LS-1 customers. Section 10.1.2 is modified, again in response to Commissioner Fessler's alternate, to include a discussion about the unit revenue requirement of special metering equipment. Both of these items were included in the findings of fact and conclusions of law issued with Commissioner Conlon's and Duque's alternate, but these conforming textual changes were omitted.

Findings of Fact

1. Edison filed the application for its general rate case for test year 1995 on December 27, 1993. At that time, Edison requested an increase of approximately $117 million over the expected December 31, 1994 ALBRR for test year 1995. In addition, the company sought attrition year rate increases of $120.955 million beginning January 1, 1996 and $111.171 million beginning January 1, 1997.

2. Edison's final litigation position was a requested increase of $62.980 million, with attrition year increases of $92.1 million for 1996 and $96.8 million for 1997.

3. On November 16, 1994, Edison, SDG&E, and DRA ("settling parties") filed a Joint Motion for Adoption of Settlement Agreement, together with the settlement agreement and a joint comparison exhibit. The settlement proposes a resolution of Phase 1 and Phase 3 issues in this general rate case.

4. Our settlement rules do not require that all interested parties participate in the preliminary discussions leading to the settlement. The settling parties met Rule 51.1(b)'s requirements by holding a properly noticed settlement conference on September 20, 1994.

5. If the settling parties choose not to accommodate all affected interest groups, they run the risk of not achieving an all-party settlement, and thus heightening the Commission's standard of review as they have done in this case.

6. Approximately 13 parties active in the 1994 evidentiary stage oppose the settlement, and most oppose it strongly.

7. When the DSM and RD&D accounts are deducted from both Edison's December 31, 1994 ALBRR and the settlement ALBRR, the settlement actually proposes for the remaining Edison accounts a $58.413 million increase from Edison's December 31, 1994 ALBRR

8. In the Phase 1 evidentiary record, Edison failed to meet its burden of proof in its funding request for several accounts more specifically set forth in the decision.

9. Under the Edison and SDG&E Phase 3 proposal, the revenue requirement will exceed the revenue requirement under existing ratemaking due to the accelerated depreciation of SONGS 2 & 3.

10. The ability to shut SONGS 2&3 without prior Commission review and approval seriously erodes asserted ratepayer benefits from the ICIP provisions of the settlement.

11. The Commission has approved the construction of plants (such as nuclear or hydro) with high capital costs but low operating costs, partly in recognition of the benefit of the low costs which can occur after the utility recovers its original plant investment.

12. Under the Edison and SDG&E proposal, the utilities will not have an obligation to serve ratepayers after 2003 with SONGS 2&3 generation after 2003. After 2003, the utilities can either shut down the plant or sell energy at market prices to any customer.

13. DRA has a compliance, and not an advocacy, role at the NOI stage of a general rate case.

14. A reasonable forecast for the test year is that Edison will serve 4,180,340 customers and sell 72,070 gWh of electricity.

15. Subject to certain modifications, the framework proposed by Edison and SDG&E to address SONGS 2 & 3 issues reasonably balances ratepayer interests with the need to transition to a more competitive electric services industry, and is similar to the treatment of stranded costs adopted in our electric restructuring rulemaking (R.94-04-031/I.94-04-032).

16. A flexible refueling outage schedule permits Edison to estimate attrition year refueling outage expenses in the event the

number of outages in the attrition year differs from the number in the test year.

17. The wicket gate expense is a nonrecurring expense related to a specific plant.

18. The mechanically switched capacitor at PG&E's Table Mountain Substation was needed to prevent low voltage conditions during certain disturbances.

19. The mechanically switched capacitor capital cost was $3,999,000, of which Edison assigned $544,000 to the High Voltage Direct Current Expansion Project and $3,455,000 to the Pacific Intertie voltage support.

20. Edison did not demonstrate that the COT project ran its course during a period of unusual and protracted uncertainty.

21. Because Edison's cost-effectiveness analysis was heavily disputed during the pendency of the COT project application, and Edison did not meet its burden of proof on certain aspects of cost-effectiveness, Edison did not meet its burden of proof that the project was reasonable during the pendency of its application because Edison believed the project was cost-effective.

22. The COT project was cancelled.

23. D.92-06-020 ordered Edison to meet with its streetlight customers and report on the outcome, both of which Edison has done.

24. Edison's acquisition program appears to fulfill its obligation to serve LS-2 customers desiring to migrate to Schedule LS-1.

25. Determining the costs certain customers impose upon the utility system is one factor in determining the appropriate level of the service establishment charge. However, cost is not the sole factor relevant to our inquiry.

26. An increase in the customer service charges would disproportionately impact low-income customers.

27. Edison has not demonstrated it has fully investigated and implemented appropriate cost efficiencies in the areas of customer service charges.

28. An increase in customer service activities should cause an increase in cost to the utility as well as an increase in operating revenue.

29. The settling parties propose $47.2 million for Edison's DSM program and $23.9 million for O&M activities.

30. Because of the pendency of the electric industry restructuring proceeding (R.94-04-031/I.94-04-032), there exists some uncertainty regarding the role of the utility in DSM. Consistent with PU Code § 701.1, we authorize a DSM budget which provides for substantial utility commitment to DSM in the face of uncertainty.

31. We require Edison to establish a two-way balancing account for its retrofit and new construction programs in order to implement its funding flexibility.

32. Edison is authorized to carry over funds directed to DSM Bidding to meet commitments beyond the rate case cycle should they occur. Funding for both the residential and nonresidential DSM bidding levels is for three years only (i.e., from 1995-1997).

33. Economic conditions have negatively impacted residential new construction program accomplishments in recent years.

34. Within the funds we have authorized for nonresidential EMS activities, we expect that Edison will continue to offer service and audits to all customer groups, investigate additional approaches to achieve energy efficiency in the nonresidential market, as well as provide Major Customer Contact services.

35. Our DSM rules provide that DAP funding should not be based purely on cost-effectiveness. Rather, DAP funding levels should be based on a reasonable balance between the needs within the community and the costs to ratepayers.

36. Edison proposed to rely on use of carryover funds to meet the true needs of its low-income customers, instead of providing sufficient funds in the settlement.

37. The DSM Test Project is an existing commitment that has been fully funded in Resolution E-3414 utilizing carryover funds. No additional funds are necessary for this project.

38. Edison did not demonstrate that its fuel substitution programs meet our three-prong test.

39. Changing the name of a program and requesting different accounting treatment, or stating that the program is necessary to meet customer-specific needs, does not change Edison's requirement to meet its burden of proof to receive ratepayer funding for programs and activities which have DSM impacts.

40. Edison did not demonstrate that its commercialization or technologies activities comply with Commission rules.

41. Edison has barely met its burden of proof in demonstrating that the ratepayer benefits it states occur as a result of the RIM test results outweigh the short and long-term resource acquisition costs associated with the proposed economic development program. These shortcomings in Edison's analysis, offset in part by the current economic conditions in Southern California, affect our determination of the appropriate funding level for Edison's economic development activities.

42. Edison has not met its burden of proof in justifying such a significant increase (almost 200% since 1991) in its requested budget for regional governmental affairs.

43. Account 426.4 describes lobbying expenses as activities conducted for the purpose of influencing public officials' decisions. It does not limit lobbying expenses to those activities occurring directly with public officials.

44. Influencing the decisions of public officials through staff members of regulatory agencies should not be funded by

ratepayers any more than direct contact with these public officials should.

45. Edison has failed to demonstrate that videoconferencing is a more cost-effective method to conduct employee meetings than other existing methods.

46. We have a long-standing policy not to require ratepayers to fund dues to chambers of commerce and service clubs for ratemaking purposes.

47. Edison's 1993 study conducted in accordance with the Uniform System of Accounts concluded that an 18% capitalization rate should be used to allocate Account 920 and 921 expenses to construction, and DRA agreed with the 18% rate.

48. After Edison filed its application, the Commission issued D.94-05-020 which adopted a multiparty settlement concerning rate recovery of hazardous waste investigation and remediation costs. Edison therefore withdrew $1.3 million from its request for environmental clean-up costs.

49. To the extent that shareholders benefit from D&O liability insurance coverage, they should also share in the expense.

50. Edison's forecast of its Workers' Compensation costs is reasonable and should be adopted.

51. One of the policies behind AR-12 is that costs incurred in meritorious employment discrimination suits should not be charged to ratepayers.

52. Edison developed its recommended franchise fee factor of 0.8375% through linear trending of recorded 1986-1992 franchise fee factors. Edison stated that the upward trend in the franchise fee factor is driven primarily by new incorporations in its service territory.

53. No new incorporations took place in calendar years 1992, 1993, 1994, or as of April 1995 (the conclusion of the Phase 1 portion of the settlement hearings).

54. The Mohave and Palo Verde costs are one-time expenses which will likely not recur.

55. Edison reports certain proceeding costs to FERC on a FERC Form 1 on an annual basis. Edison should provide this information to DRA upon request as appropriate in future proceedings.

56. In Edison's last general rate case, we denied Edison recovery of expenses associated with its Board of Directors' pension plan.

57. Actions taken or items discussed at a board meeting may involve issues that affect Edison or SCEcorp and we decline, based on the record in this case, to modify the multifactor formula we set forth in D.88-01-063, 27 CPUC2d 347, 388 which we use to allocate directors' fees.

58. In D.91-12-076, 42 CPUC2d at 689, we denied Edison recovery for NMRC dues and rejected Edison's conclusion that the NMRC's purpose excludes advocacy. We are not convinced by this record that the NMRC's purpose has changed since Edison's last general rate case.

59. In D.89-12-057, 34 CPUC2d 199, 266-269, the Commission denied authorization of ratepayer funding for the portion of the EEI dues which relate to legislative policy research, legislative advocacy, contributions and club dues.

60. We have established a CEMA account by Resolution E-3238 for a utility to record costs of, among other things, repairing, replacing or restoring damaged utility facilities caused by certain disasters and to subsequently seek rate recovery. The CEMA account is used by utilities to record certain extraordinary expenses, such as those resulting from large earthquakes.

61. DRA's four-year average is reasonable in determining Account 935 reserve costs because we do not think it necessary to include certain extraordinary expenses, such as those resulting from large earthquakes, in Account 935 reserve costs.

62. DRA misconstrued the statistical relationship between ECIBPNS and Edison's recorded Account 926.1 costs.

63. We cannot endorse Edison's conclusion that the linear regression results confirm Edison's test year estimate.

64. Two decades of runaway health care inflation appears to have halted.

65. Edison is only now showing movement toward large-scale HMO enrollment.

66. In order to have absorbed the "one-time" savings over the period of its cost containment program (which began in 1989), Edison's annual rate of cost escalation would have had to run about 2% lower than the national rate (extrapolating the ECIBPNS health subindices through 1994).

67. Edison's health care request does not reflect "one-time" dividends comparable even to what other Western firms enjoyed in 1993-1994, as reported by Foster Higgins. Edison has not of late managed its health care costs as successfully as the typical western firm in the Foster Higgins survey.

68. The "one-time" savings from the shift toward lower cost health plan types is an important but not the exclusive factor in arresting health care inflation. In California, a very prominent example of such a cost-management technique has been the deployment of aggressive purchasing strategies, either via a pooling arrangement or singly through enterprising price shopping.

69. Edison failed to actively pursue lower-cost health care contracts during a period when others did so with demonstrable success.

70. With respect to the appropriate 1993-1995 trend rates for non-HMO insurance categories, more recent trend rates from a nearby region should carry more weight than older, national rates.

71. In Phase 2 of this proceeding, DRA has proposed abolishing the 25% domestic rate discount for Edison employees. Edison's Phase 1 request included an additional $0.7 million to

reimburse those employees (and retirees) who, because they live outside Edison's service territory, would not otherwise receive the discount.

72. We believe it equitable to offset the $1.5 million capitalization error against the increase in property insurance, and therefore do not reduce Account 926 further for this item.

73. The settling parties have achieved reduced funding levels in RD&D by extending project area schedules or elements, and by eliminating generation-related project areas. As a result, the impact of the reduced funding is to spread out the projects over a somewhat longer period of time, and probably prevent Edison from funding new research projects that may have been undertaken.

74. Currently there exists some uncertainty regarding the role of the utility in RD&D. The level we authorize today reflects this uncertainty.

75. Allowing Edison to use ratepayer funds to perform certain generation-related research at this time could be viewed as anticompetitive in a future that does not view generation as a continuing monopoly function of the utility, or because it might not provide benefits to Edison's particular ratepayers if Edison does not continue in the new generation business. However, we will continue to fund certain projects within the Advanced Generation Program through December 31, 1997. Funding is authorized for these projects in order to maintain some continuity for these programs in the face of uncertainty surrounding restructuring of California's electric industry. We believe research in this area provides the potential for long-term environmental and resource diversity benefits for ratepayers that outweigh potential anticompetitive concerns associated with ratepayer funding in this area at this time.

76. No party to the settlement proceedings contends that the RD&D portion is inconsistent with the guidelines set forth in PU Code § 740.1.

77. We decide the appropriate project area funding levels based on Edison's original request, the parties' initial positions, the settlement, and the intervenors' responses to the settlement.

78. The issue of curtailment of all funding after December 1997 for "incremental generation" project areas is beyond the scope of the current rate case cycle and is of broader policy concern.

79. Additional research of off-grid PVs is not warranted at this time.

80. Edison's proposed PV on-grid research is justified.

81. The additional potential benefits for the distributed fuel cell project area cited by Edison convinces us to allow partial funding. The issue of curtailment of all funding in this area after December 1997 is beyond the scope of the current rate case cycle and is of broader policy concern.

82. DRA's initial arguments and those offered by the settling parties convince us to not authorize funding for the Heat Rate Improvement, Diagnostic Monitoring and Control, Improved O&M, Electrical Efficiency Improvements, and Advanced Gas Turbines project areas.

83. Edison's projects within the Protective Devices and Transmission Stability & Control Project Areas are designed to increase operating efficiency and system versatility. The schedules may be extended without jeopardizing the projects.

84. High-speed electric mass transit and heavy rail (commuter and freight) systems are currently being developed in Edison's service territory. While Edison should not be investigating the feasibility of such systems with ratepayer funds, it is Edison's responsibility to ensure that its system can serve the potentially large loads associated with the rail systems.

85. DRA has not successfully challenged the merits, the forecasted benefits, or the need for any of the individual proposed research projects in the Customer Energy Technologies subprogram

The project schedules may be extended without jeopardizing the projects.

86. In D.93-12-043, we stated that it is not appropriate to use ratepayer funds to support research to assist individual customers with their own end-use air quality compliance.

87. The settlement's substantial funding reduction for the Environmental Research Sub-Program is consistent with the expected shift in Edison's role away from power generation.

88. We find DRA's original testimony on the Work Health Exposures project area, that Edison should not bear over half of total research costs, convincing and do not adopt any funding for the Work Health Exposures project area.

89. The additional $458,000 for RD&D O&M expenditures is necessary to develop the future business framework of Edison's Technology Planning and Development (TP&D) Department.

90. Since contractor/consultant costs are allowable under our definition of RD&D, we will allow the $36,000 funding to be included in the Research Management & Support Sub-Program but with the specific proviso that it my be used for travel and supply expenses, temporary non-Edison personnel, and facilities expenses only.

91. In D.93-07-054, we directed utilities to request <u>all</u> utility funding requirements related to LEVs for a six-year cycle by filing special applications in the rulemaking proceeding.

92. EPRI performs scientific research on the production, transmission, distribution and utilization of electric power for the intended benefit of utilities, their customers and the public. CIEE researches and demonstrates efficient end-use energy technologies and processes. WEST Associates provides a forum for utility managers to exchange information and attend conferences to discuss regional issues relating to electric utilities.

93. In D.91-12-076, we ordered a financial audit of Edison's RD&D activities and expenditures for the years 1988 through 1992.

to be submitted in Edison's next (1995) general rate case. CACD retained BWG to perform this audit. CACD filed BWG's report in June, 1993, and it was submitted as Exhibit 62 in this case.

94. In D.87-12-066, we required Edison to establish and maintain a separate one-way balancing account for RD&D so that unexpended funds could be returned to ratepayers, with interest. Resolution E-3275 clarified that the one-way balancing account rules apply on an annual, not general rate case cycle, basis.

95. On March 31, 1995, Edison filed two advice letters to reconcile the one-way balancing accounts for its 1988-1991 and its 1992-1994 general rate case cycle. Contrary to Edison's original request in this case, Edison trued up the accounts on an annual basis.

96. We clarified in Resolution E-3376 that if a utility has received authorization to record expenditures in its RD&D one-way balancing account over the general rate case cycle, then it is reasonable to allow it to apply the fund shifting guidelines over the rate case cycle as well.

97. Since we have authorized Edison the balancing account flexibility, we think it is appropriate to grant Edison the corresponding flexibility with respect to fund shifting.

98. Our establishment of an RD&D funding range does not mean that Edison's RD&D funding requests cannot be higher (or lower) than the funding range. The funding range means that, if the utility's rate request for RD&D spending is within the funding range ordered in the current rate case, it would focus the discussion of RD&D on broad RD&D program directions. Only when the utility's RD&D program request rose above the ceiling or fell below the floor would detailed information be required in the initial filing.

99. Ratepayers receive benefits from superior off-system sales performance, and it is appropriate to compensate shareholders for costs associated with these sales.

100. Our record is inadequate to approve any specific methodology for calculating the O&M adder which relates to off-system sales. However, given that we believe it is appropriate to provide an incentive to shareholders to make off-system sales, we determine a reasonable value for the adder based on the existing record.

101. The Edison, DRA, and TURN estimates for the adder are consistent on the value of consumables.

102. We do not include long-term standby savings in our adopted value for the adder since off-system sales are possible only because there is long-term excess capacity and should be reduced when long-term resources diminish.

103. If overhaul costs are fixed, they would not vary with off-system sales since they would be covered in O&M cost categories that are not associated with off-system sales. If they are variable, then they should be estimated and included in the adder.

104. We assign a value for overhaul costs of 0.26, which is half of the value proposed by Edison.

105. Since we have repeatedly stated that we would not permit methodological changes to the calculation of the QF O&M adder in ECAC proceedings, we reject a similar suggestion that the Commission revisit the off-system adder values adopted in this decision in each annual ECAC proceeding.

106. The ALJ granted Edison's motion to strike DRA's rebuttal to Edison's additional off-system sales testimony without prejudice to DRA to introduce such testimony in another proceeding such as the OII portion of Edison's PBR application. The ALJ's ruling should be affirmed.

107. The value adopted in this proceeding for the O&M adder should not be regarded as precedential for setting the appropriate value for QF avoided O&M costs in future ECAC proceedings.

108. The intent of Resolution E-3369 is to authorize the level of costs to be recorded in a memorandum account, and to have the

appropriate rate determined in the off-system power sales incentive mechanism application (OPSIM) or other proceeding (such as this general rate case) prior to the Commission's authorization for rate recovery.

109. The Internal Revenue Service now requires unit specific information on decommissioning costs from the utility's most recent cost of service proceeding such as this general rate case.

110. In making the decision in 1985 that the utility should finance its fuel oil inventory through some form of short-term debt rather than shareholder equity, the Commission primarily focused on a risk analysis.

111. The risk Edison is offering to assume is not significant enough to justify a change in financing of the carrying costs, especially when Edison has not met its burden of proof in demonstrating the rate impact and cost-effectiveness of its proposal.

112. The portion of the fuel oil inventories which Edison proposes to rate base are the portion of the inventories whose volume is more stable than the remaining portion (i.e., according to Edison, the minimal inventory which should be maintained over the long term to assure continued reliable operations).

113. It is more efficient to include determinations of the reasonableness of fuel inventory levels in the ECAC proceeding.

114. Edison and DRA reached an impasse on the issue of preparing a total compensation study as required by D.91-12-076.

115. The utility bears the burden to justify employee compensation levels, and that wages and salaries should be reasonable compared to the relevant market.

116. Although neither Edison nor DRA is solely to blame, both are at fault in failing to resolve their differences in complying with D.91-12-076's directives regarding a total compensation study.

117. In certain critical areas, Edison did not provide the requisite underlying data to allow us to determine that its compensation levels are reasonable.

118. Edison and DRA agree that job matching and benchmarking play a crucial role in determining total compensation.

119. In order for a total compensation study to be valid, it is critical that an accurate "apples to apples" comparison be made for each job match.

120. Edison has not met its burden of proving that its job matching and benchmarking decisions are reasonable.

121. Edison's job matches and benchmarks appear incomplete.

122. Given the problems we find in Edison's and DRA's total compensation showing, the record does not provide a reasonable figure for Edison's total compensation budget.

123. The revenue requirement we authorize today for Edison's total compensation expenses is for test year 1995, and is not necessarily the revenue requirement which should serve as the basis for PBR.

124. We are not preempted from reviewing and making any adjustment to Edison's compensation request.

125. Our review of Edison's description of the Steam WMS project forces us to agree with DRA's conclusion that a 6.25% productivity improvement spread over 1,634 employees is a straightforward cost reduction.

126. Edison's description of the benefits of the Steam ISIS project is strikingly similar to its discussion of the Steam WMS project: reductions in overtime and contractor utilization, reductions in time required to perform standard tasks, reductions in equipment service time, and improved unit reliability.

127. Beyond the $3.158 million associated with the Steam WMS, we have reclassified 1/2 of an additional $4.356 million in cost avoidances as cost reductions to be included as O&M software savings for test year 1995.

128. Edison fails to provide a persuasive basis for completely excluding the "productivity/other" estimate from the O&M savings total.

129. The attrition mechanism originated in SoCalGas' 1981 general rate case, D.92497, 4 CPUC2d 725, 770 (1980). The mechanism was designed to protect the utility from extraordinarily high inflation rates and unpredictable changes in financial markets which might jeopardize the utility's opportunity to earn its authorized rate of return.

130. Conditions have changed since 1985 in ways that require us to reconsider the viability of the attrition year adjustment.

131. If Edison believes that extraordinary circumstances arise which require rate increases before a form of PBR is implemented, Edison can file an application (not an Advice Letter) to make this request with specificity and to state how the request is compatible with its other requests and our other pending proceedings.

132. Edison has provided estimates of the unit revenue requirements of special metering equipment for use in Phase 2 of this general rate case pursuant to D.93-07-030. These estimates were uncontested, are reasonable, and should be adopted.

<u>Conclusions of Law</u>

1. TURN's unopposed motion for acceptance of late filed findings of fact and conclusions of law, dated August 22, 1994, should be granted.

2. Edison's motion to strike DGS' Phase 1 settlement brief should be denied.

3. Since we have delayed the resolution of this proceeding in order to consider the settlement, fairness and our obligation to the public interest requires that we consider the most recent evidence available at the settlement hearings.

4. The settlement before us is not reasonable in light of the whole record, consistent with the law, and in the public interest, and should be rejected.

5. Subject to certain modifications, the framework proposed by Edison and SDG&E to address cost recovery issues of SONGS 2 & 3 is reasonable and should be adopted. Edison and SDG&E should have the ability to respond to the policy we propose for SONGS as discussed in Section 3 of this decision within 25 days of the effective date of this decision. CBERT's motion to consolidate our review of the settlement with our electric industry restructuring proceeding should be denied.

6. At the conclusion of evidentiary hearings, Edison and DRA agreed on Edison's Steam and Other Power Production O&M and capital expenses which we find are reasonable and should be adopted.

7. DRA's proposal that the Commission amortize the SONGS 2&3 O&M savings realized in the attrition years over the rate case cycle should be denied.

8. DRA's recommendation that the nuclear O&M expenses estimated to increase total capacity factor be shared 50/50 between shareholders and ratepayers should be denied because the expenditures are necessary to maintain ongoing programs implemented during periods of improving plant performance.

9. Edison's requested nuclear O&M expenses should be reduced by $232,000 for expenses from Edison's forecast of PVNGS oversight expenses.

10. DRA's recommendation that Edison's capital expenses should be reduced by $5.3 million per unit should be denied in that Edison's PMRO has now approved the projects.

11. Edison's nuclear capital expenses as of the close of evidentiary hearings are reasonable and should be adopted.

12. Edison should file its flexible refueling outage schedule request as an advice letter in attrition years using test year values of O&M expenses for refueling. Edison should not expand this filing to include other items not previously included in the

flexible refueling outage schedule request, such as escalation fees associated with the disposal of low-level nuclear waste.

13. The cost of wicket gates should be capitalized and expenses in Account 544.100 should be reduced by $649,000 with a corresponding increase in plant-in-service.

14. Edison's hydro capital estimates at the close of evidentiary hearings, with the adjustment for the wicket gates recommended by TURN, are reasonable and should be adopted.

15. TURN's recommendation that the Commission reduce Edison's transmission expenses by $250,000 for certain training and safety meeting costs should be denied.

16. Edison should reduce its transmission O&M expenses for the Sylmar Converter Station by $156,000 because Edison has not shown why these costs should increase.

17. Edison should use the same estimating methodology for similar accounts for consistency of evaluation. Therefore, TURN's requested disallowance of an $18,000 reduction of labor and a $308,000 reduction in nonlabor expenses for Edison's transmission structural maintenance expenses and a $171,000 reduction for the provision of property damage expenses should be granted.

18. No party opposed Edison's estimate of $313.587 million for transmission capital expenses, which is reasonable and should be adopted.

19. Edison should refund to ratepayers $225,000 through a credit to the ERAM balancing account for Edison's 1992 overcollection of the costs of mechanically switched capacitor equipment at Table Mountain. The refund should be adjusted to include interest charges for the period ending January 19, 1996, and should become effective on January 20, 1996.

20. Edison should not be allowed to claim any O&M expenses for the mechanically switched capacitor equipment until after July 2013 unless the 23-year agreement between PG&E and LADWP is cancelled or modified.

21. Edison should prepare a report on how the upgraded transmission-related equipment, such as circuit breakers, disconnect switches, transformers, etc. related to the 500 kilovolt (kV), 200kV and other substations, performed during the January 17, 1994 Northridge earthquake, and what changes should be considered with respect to transmission lines and other lower voltage facilities in its Seismic Upgrade Program. Edison should also include in its report a short discussion of its seismic damage insurance coverage, if any, for these facilities. Edison should file this report no later than March 1, 1996 in this docket and serve it on the parties to this proceeding as well as on the Commission's Safety and Enforcement Division.

22. Edison should consider the use of more compact designs for its new substations and lines, to the extent these designs are a cost-effective means of reducing land, right-of-way, and equipment costs.

23. Edison should include certain information as set forth in Section 8.2 with its application for a reinstated or new CPCN for the Devers-Palo Verde No. 2 500 kV line.

24. Edison's request to recover the funds it invested in the COT project should be denied because Edison has not met its burden of proof in demonstrating cost recovery.

25. TURN's recommended reduction of $23,000 to Edison's EMF expenses, to which Edison agreed, should be granted. TURN's additional recommended reductions to Edison's Electric Distribution O&M account should be denied.

26. Edison's Electric Distribution O&M and Capital expenses as proposed at the close of evidentiary hearings are reasonable and should be adopted, subject to adjustment for our adopted customer growth figure.

27. Beginning in 1996 and ending in 1998, Edison should file an annual report no later than March 1 of each year indicating (1) the number of pole inspections and inspections of underground

structures it has conducted in the prior year, and (2) the number of pole inspections and inspections of underground structures it forecasted in its general rate case testimony for that year. This report should be filed with the Commission in this docket and served on CACD as well as all parties to this case. If at the end of any year Edison has failed to meet its targeted (i.e., forecasted) goals, we will consider imposing penalties on Edison for compromising the safety of its distribution system.

28. Edison and DRA agreed that a multiplier of $1,719 in constant 1993 dollars is appropriate to determine the distribution capital cost per customer. We agree that this multiplier is reasonable and should be adopted.

29. Edison's streetlight acquisition program should be conditionally approved, pending a quantitative demonstration that all components of the program's revenue requirement (including return on rate base, franchise fees and uncollectibles, etc.) will be borne only by participating LS-1 customers (and to take appropriate corrective rate design measures as needed). Edison should make this demonstration no later than February 29, 1996 in this proceeding. If Edison's filing is contested, the issue should be resolved in Edison's next rate design window or other appropriate forum as determined by the Assigned ALJ.

30. Edison has adequately justified its cost-containment measures for meter reading expenses. Edison's meter reading expenses are reasonable and should be adopted.

31. Edison's request to increase and add certain customer service charges should be granted to the extent set forth in Section 10.2.

32. Since we do not approve the Late Payment Charge, the average number of lag days for Edison's residential class estimate should be increased by one and one-half days in order to determine its working cash requirement.

33. Edison's and CSB's petition for modification of D.94-12-045 should be denied.

34. A total of $65.8 million for Edison's DSM programs and a total of $9.65 million for Edison's CS&I and Sales O&M programs as more specifically set forth in Section 11 and Table 11-3 are reasonable and should be adopted.

35. We do not exempt Edison's requested ratepayer funding of activities that cause DSM impacts from scrutiny under our DSM rules, simply because Edison has changed the name or accounting treatment of certain activities. Consistent with our pronouncement in past decisions, changes to our DSM rules should be raised in R.91-08-003/I.91-08-002 (the DSM Rulemaking/Investigation).

36. After meeting and conferring with interested parties from this proceeding and its Advisory Committee, Edison should file an Advice Letter which assigns the adopted funding in Section 11 to the proper FERC accounts. This Advice Letter should be filed within 60 days of the effective date of this decision. If the parties do not reach consensus, the Advice Letter should state Edison's preference, as well as all alternative positions of other parties.

37. Edison should work with its Advisory Committee to actively explore alternate delivery mechanisms for its RABI and NEEI programs.

38. For all of the retrofit programs, Edison should not implement DSM measures that are not cost-effective at the end use level. Edison should (1) update its cost-effectiveness tests using adopted electric avoided costs and (2) demonstrate that the measures it plans to pursue pass the TRC and UC tests consistent with our DSM rules. Edison should file this update as an Advice Letter filing within 60 days of the effective date of this decision. Funds for these programs will receive two-way balancing account treatment.

39. For all of the new construction programs, Edison should (1) update its cost-effectiveness tests using adopted electric avoided costs and (2) demonstrate that the program it plans to pursue passes the TRC and UC tests consistent with our DSM rules. Edison should file this update as an Advice Letter filing within 60 days of the effective date of this decision. Funds for these programs will receive two-way balancing account treatment.

40. Residential New Construction should be a line item in Edison's residential portfolio for purposes of shareholder earnings and fund shifting, with zero dollars allocated.

41. When determining funding priority, Edison should work with low-income representatives to determine which types of programs best assist low-income customers in managing their energy bills.

42. Edison should work with DRA to develop an appropriate allocation mechanism between DSM and O&M costs for outreach activities.

43. Edison should return the carryover funding it received to meet additional need for low-income services in 1995, authorized in Resolution E-3414, to ratepayers. Edison should file a report within 60 days of the effective date of this decision setting forth how it has returned the carryover funding to the ratepayers.

44. Edison should initially be allowed no more than $2.989 million for test year 1995 for its economic development program.

45. Edison's economic development request with respect to CALSTART should be denied, as Edison should have raised this issue in our low-emission vehicle proceeding (I.91-10-029/R.91-10-028).

46. Edison's request for local governmental affairs expenses is reasonable and should be adopted. Edison's request for regional governmental affairs expenses should be reduced by one half of DRA's requested reduction of $1.1 million.

47. Edison's requested $667,300 for its educational program, Step Up, should be denied because it appears to be a program in the

nature of a charitable contribution and the benefits cited by Edison are too difficult to demonstrate and quantify to justify the use of ratepayer funding.

48. DRA's requested reduction of $366,560 for expenses associated with CTAC should be denied since DRA did not question the reasonableness of these costs, but merely their reclassification.

49. We grant DRA's requested reduction of $67,000 for a corporate communications survey because we are not convinced we should authorize a new annual survey when Edison has not demonstrated that existing means (i.e., measurement and evaluation studies in DSM, management supervision of employees) are not adequate to ascertain effective communication.

50. Edison's' Account 920 expenses for regulatory and policy affairs should be reduced by $501,930 for lobbying activities.

51. Edison's Account 920 expenses should be reduced by $380,292 because we are not convinced that the 1992 recorded severance payments made by Edison to the law department employees are likely to recur in the test year.

52. Edison's Account 920 expenses should be reduced by $87,000 for expenses for the employee volunteer program since these employees are similar to charitable contributions.

53. Edison's Account 920 expenses should be reduced by $7,100 for High Five Service Program costs since Edison did not demonstrate that expenses from the prior quality of service program were also removed from the base year.

54. Edison's Account 920 expenses should be reduced by $887,149 to eliminate expenses for videoconferencing and floral centerpieces.

55. Edison's Account 921 expenses should be reduced by $101,000 to exclude expenses for all employee chamber of commerce dues and certain other employee membership dues since such organizations are unrelated to utility business.

56. Edison's Account 923 expenses for outside services should be reduced an additional $2.029 million since DRA identified outside services that will end between 1992 and 1995 without corresponding new or replacement activities to justify Edison's request.

57. Edison's Account 926.1 expenses should be reduced by an additional $788,000. We believe this is a conservative reduction given Edison's lack of specific documentation (i.e., the lack of actual past expenses for contract medical workers) on this issue.

58. Edison's estimates for Accounts 923, 924, 925 and 926 should be reduced by $124,000 to reflect additional savings from the displacement of outside counsel that Edison would realize as a result of hiring ten attorneys to its law department between 1993 and 1995.

59. Edison's Account 924 expenses should be reduced by $321,000, which reflect the 1988 - 1992 litigation costs associated with a case between Edison and Westinghouse which settled in 1993, since expenses similar to the settled case are not representative of similar future litigation costs.

60. Edison's Account 924 expenses for blanket crime insurance should be reduced by $34,203 and the Account 925 expenses for medical malpractice insurance should be reduced by $19,244 because the premium increases are effective mid-year, yet Edison assumed the increases to be effective January 1, 1995. Edison's medical malpractice insurance should also be reduced by $23,000 based on the fact that a reduction in medical personnel could decrease premium costs.

61. Edison's requested $2.873 million for D&O liability insurance premiums should be reduced by 50% since shareholders as well as ratepayers benefit from this coverage.

62. Edison's test year expense estimate for Account 925 injuries and damages claims should be reduced by $62,000 by

estimating both departmental and general expenses using a five-year average.

63. Edison's estimate for workers' compensation expenses is reasonable and should be adopted.

64. Edison's request of $149,000 for an injuries and damages reserve in connection with Edison's share of the PVNGS is reasonable and should be adopted.

65. DRA's request to disallow $667,000 for Account 925 expenses related to discrimination lawsuits should be granted.

66. FEA's recommended method of determining the franchise fee factor, resulting in a franchise fee factor of 0.8087% should be adopted.

67. The Net-to-Gross multiplier should be adjusted to reflect our adopted franchise fee factor.

68. Edison's expenses for outside counsel regulatory commission expenses should be reduced by $1.970 million to exclude costs associated with two Commission proceedings (the Mojave Coal Plant Investigation, I.86-04-002 and the Palo Verde Nuclear Generating Investigation, I.89-12-025.)

69. Edison's request of $220,000 for Account 928 regulatory and policy affairs expenses, which is less than half the recorded and adjusted amounts for 1992, is reasonable and should be adopted.

70. Edison's requested $68,000 for its advertising manager's salary is reasonable and should adopted.

71. Edison's requested expenses of $940,000 associated with its Board of Directors' pension plan should be denied.

72. Edison's requested $607,000 for Directors' fees and retainers, which it states are necessary for attracting well qualified individuals to serve on its Board of Directors, is reasonable and should be adopted.

73. DRA's recommended $74,690 disallowance of corporate chamber of commerce dues and $25,006 disallowance of other corporate association dues for Account 930.2 should be granted.

74. Account 930.2 should be reduced by $126,000 attributable to NMRC dues.

75. The portion of EEI dues related to legislative policy research and regulatory advocacy, as well as institutional advertising and public relations, should be excluded from Edison's test year expenses.

76. The EEI dues should not be reduced for the amount attributable to contributions and club dues, because Edison has reduced the dues for these items.

77. Edison's $200,000 estimate for maintenance at the Gateway Birtcher facility is reasonable and should be adopted.

78. Edison's expenses of $17,000 labor and $9,000 nonlabor for technician expenses associated with maintaining additional installations of IPCs and RTUs should be rejected because there is insufficient record evidence that technician expenses will increase even if IPCs and RTUs increase.

79. Edison's Account 935 reserve expenses should be reduced by $442,000.

80. Edison's forecast of $304 million for A&G capital expenditures, the majority of which relate to telecommunications equipment and mainframe computing, is reasonable and should be adopted.

81. For ratemaking purposes, we should adopt health care trend rates which compensate ratepayers for Edison's forgone opportunity to take advantage of the emerging buyers' market which Edison could have done by reacting sooner, and, for example, using its regional leadership concept to combine its purchasing power with other businesses.

82. TURN's common sense approach regarding 1993 and 1995 trend rates for non-HMO insurance categories is reasonable and should be adopted. TURN's PrimeCare correction should also be adopted.

83. Edison's 1992-1995 administrative health care cost increase is not necessarily a one-time change given its ongoing

activities in health care plan development and management, and therefore Edison's proposed administrative budget should be adopted.

84. A health care budget of $140.487 million is reasonable and should be adopted.

85. DRA's requested disallowance of $1.2 million for miscellaneous employee benefits should be granted since these expenses have a predominantly social character.

86. The reimbursement funding of $0.7 million for the 25% domestic rate discount for Edison employees who live outside the service territory should not be adopted pending resolution of the domestic rate issue in Phase 2. These funds may be restored by the Advice Letter process in the event our Phase 2 decision retains the employee discount.

87. A total funding level of $27.465 million for RD&D and $458,000 for RD&D O&M expenses, as more specifically set forth in Section 15 and Table 15-1, is reasonable and should be adopted.

88. SCEcorp should be allowed to fund research and commercialization of the AIR project, provided that it reimburses ratepayers $100,000 for this project if it decides to pursue the research.

89. Funding for the four RD&D project areas in the Customer Air Quality Improvement sub-program, totalling $2.498 million, should be denied.

90. The expenses for the Research Management and Support sub-program should be reduced by $278,000 since we directed utilities to request all LEV funding in the LEV rulemaking.

91. The settlement funding for EPRI membership is the result of reduced funding for generation-related business units and should be adopted, given our previously stated position regarding generation related research. With respect to CIEE, Edison's original funding request of $1 million should be adopted.

settlement's recommendation to cancel Edison's membership with WEST Associates should be adopted.

92. Edison should not adopt the BWG recommendation concerning the General Auditor but should adopt all of BWG's other outstanding financial and management/policy recommendations as set forth in Section 15.

93. We intend to address Edison's advice letters seeking to reconcile the one-way balancing accounts for its 1988-1991 and its 1992-1994 general rate case cycle in Commission Resolutions. The reconciliation of Edison's balancing account over the 1995 general rate case cycle should be consistent with the rules set forth for PG&E in D.92-12-057.

94. All revenues recorded in the royalty memorandum account for Edison's 1992 general rate case cycle should be returned to ratepayers by an advice letter filing on or before March 31, 1996. All revenues recorded in the royalty memorandum account for the 1995 general rate case cycle should be returned to ratepayers by an advice letter filing on or before March 31, 1998.

95. A funding range of 0.4% to 0.6% for RD&D should be established for Edison.

96. Edison's proposed changes to Tariff Rule 2, Section H should be adopted. Because we address this issue and approve these changes today, the changes should not be retroactive to January 1, 1995.

97. An adder value of 0.53 mills/kWh should be applied prospectively for the ratemaking treatment for each kWh of off system sales delivered after January 1, 1995, subject to our discussion of RECLAIM in Section 16. Edison's revenue requirements should be reduced by 1,595 gWh (the off-system sales forecast) times 0.53 mills/kWh.

98. Edison should credit retail ratepayers for the value of RECLAIM trading credits which are instead consumed in making off system sales. This credit will be based on the value Edison will

implement in its system dispatch computer to reflect the value of RECLAIM trading credits for purposes of making transaction decisions. Implementation should occur no later than January 19, 1996. The value of RECLAIM trading credits should be credited to ratepayers before any recovery of variable/incremental O&M costs by shareholders.

99. Edison should terminate entries to the memorandum account established by Resolution E-3369 after sales delivered through December 31, 1994 are recorded, and should recover any ending amounts based on the adopted adder of 0.53 mills/kWh, and the difference between forecast and recorded off-system sales.

100. DRA's recommendation that Edison's plant-in-service be reduced by $1.668 million in the steam category and $0.366 million in the general category should be denied because DRA has given us insufficient, summary information on which to evaluate its recommendation which, because of when it was made, was not subject to cross-examination.

101. DRA's recommended reduction of (1) $1.284 million associated with the SONGS Environmental Mitigation Project's Marine Education Center, (2) $0.498 million for the SONGS Power System Stabilizer, a portion of the SONGS Fish Hatchery Project, and the SONGS Offsite Emergency Planning Project; and (3) $2,000 of overheads should be denied.

102. TURN's recommended reduction in 1995 plant-in-service of $9,514,000 should be denied because our task in this general rate case is to set Edison's revenue requirement for test year 1995, not to make adjustments to its test year 1992 general rate case.

103. DRA's nonmonetary recommendations regarding Edison's plant forecasting model for Edison's next general rate case should be denied because we are not assured on the basis of the record that the benefits outweigh the costs.

104. TURN's recommendation that the Commission recognize lower levels of test year expense, more accurately calculate the lag days

for expenses listed as "fuel oil," and exclude Minnesota state income taxes from the calculation, should be granted.

105. TURN's request to reduce Edison's working cash requirement by $5,509,000 should be denied because we wish to avoid "double-counting" reductions.

106. Edison submitted the following unit-specific information with respect to its nuclear generation plants, which no party objected to and which should be adopted:

Line No.	Unit	Qualified ($000)	Nonqualified ($000)	Total ($000)	For Years
1.	SONGS 1	1,943	3,374	5,317	1995 - 2004
2.	SONGS 2	30,121	1,004	31,125	1995 - 2013
3.	SONGS 3	35,071	0	35,071	1995 - 2013
4.	PVNGS 1	9,250	0	9,250	1995 - 2024
5.	PVNGS 2	9,183	0	9,183	1995 - 2025
6.	PVNGS 3	9,876	0	9,876	1995 - 2027
7.	TOTAL	95,444	4,378	99,822	

107. For ratemaking purposes, none of the barrels of fuel oil inventory, coal, and the portion of in-core nuclear fuel that Edison requested in Section 17 should be included in rate base.

108. Edison's request to recover Kramer-Victor transmission line costs should be determined in A.89-03-026. No costs for this item should appear in Edison's revenue requirement resulting from this case.

109. Edison's tax expenses were undisputed, are reasonable, and should be adopted.

110. The results of Edison's total compensation showing should be utilized even though Edison has not met its burden of proof in demonstrating the reasonableness of its request. The amount of total compensation we authorize is set forth at page 29 of Appendix D.

111. Since both shareholders and ratepayers could benefit from increased productivity, half of TURN's recommended $7.385 million

reduction to Edison's total compensation request to reflect the management wage freeze should be granted.

112. TURN's proposed reduction with respect to growth in management ranks should be denied in this case. We do not pass judgment on whether TURN's proposal should be adopted in the PBR proceeding, because the full record is not before us here.

113. DRA's proposals for reasonableness reviews for capitalized software projects and quarterly progress reports for the SCEnet project should be rejected as unnecessarily burdensome.

114. A reduction for capitalized software benefits of $6.757 million, the sum of Edison's Test Year 1995 estimates for the Steam WMS cost avoidance ($3.158 million), and 1/2 of both the additional unsupported cost avoidances ($4.358 million), and the "productivity/other" projects ($2.839 million) identified in Section 20.2, should be adopted.

115. Edison should not be authorized to file an advice letter seeking attrition year increases.

116. WMA's distribution plant proposals should be denied since we find Edison has sufficiently justified its requests with respect to WMA's proposals.

117. Edison's and CSB's respective petitions to modify D.94-12-045, the Interim Decision, should be denied.

118. The Commission should adopt the revenue requirement for Edison as set forth on page 1 of Appendix B.

119. Edison should incorporate the revised ALBRR into rates ordered in its latest ECAC, A.95-05-049.

120. This decision should be effective today, so that the test year revenue requirement will be effective on January 20, 1996, as qualified by this decision.

O R D E R

IT IS ORDERED that:

1. On or before January 17, 1996, Southern California Edison Company (Edison) shall file with this Commission revised tariff sheets which implement the Authorized Level of Base Rate revenue (ALBRR) as set forth in Appendix B of this decision. On or before January 17, 1996, Edison shall also file with this Commission revised tariff sheets which (1) implement our adopted changes to Tariff Rule 2, Section H, "Added Facilities" as discussed in Section 16.1 of this decision and (2) implement our authorized changes to Customer Service Charges as discussed in Section 10.2 of this decision.

2. The revised tariff pages shall become effective January 20, 1996, and shall comply with General Order 96-A. The revised tariff sheets shall apply to service rendered on or after their effective date.

3. Edison shall incorporate the revised ALBRR into rates ordered in the forecast phase of Application 95-05-049.

4. Edison, San Diego Gas & Electric Company, and the Division of Ratepayer Advocates's Joint Motion for Adoption of Settlement Agreement, filed on November 16, 1994, is denied without prejudice to the utilities' ability to file a revised proposal in this proceeding as outlined in Section 3. Within 25 days of January 10, 1996, the effective date of this decision, Edison and SDG&E shall file with this Commission a pleading stating whether or not they are willing to offer a proposal to the SONGS 2&3 settlement consistent with our discussion in Section 3 of this decision. If the utilities accept, then they should include a revised proposal consistent with our discussion in Section 3 of this proceeding, with their filing. The utilities should also include the workpapers for the derivation of all numbers in the revised proposal, as well as workpapers showing all revenue

requirement impacts. This filing, including workpapers, should be served on all parties to this proceeding. Parties may file comments on the utilities' filing by no later than February 20, 1996. Commenting parties should serve their comments on the Commissioners and assigned Administrative Law Judge so that they are received no later than the day following service.

5. Edison's and the Cogeneration Service Bureau's respective petitions to modify Decision 94-12-045 (Interim Decision) are denied.

6. TURN's unopposed motion for acceptance of late-filed findings of fact and conclusions of law, dated August 22, 1994, is granted.

7. Edison's motion to strike the Department of General Service's Phase 1 settlement brief is denied.

8. The Center for Energy Efficiency and Renewable Technologies' motion to consolidate our review of the settlement with our electric industry restructuring proceeding is denied.

9. Edison shall refund to ratepayers $225,000 through a credit to the ERAM balancing account for Edison's 1992 overcollection of the costs of mechanically switched capacitor equipment at Table Mountain. The refund shall be adjusted to include interest charges for the period ending January 19, 1996, and shall become effective on January 20, 1996.

10. Effective January 20, 1996, Edison shall terminate the High Voltage Direct Current Expansion Project mechanically switched capacitor cost memorandum account which we ordered Edison to establish in Ordering Paragraph 7 of Decision 92-12-022. Edison shall also remove the memorandum account from its Preliminary Statement. Excepting the refund of $225,000 plus interest ordered above in Ordering Paragraph 10, amounts in the memorandum account at the time of its termination shall not be refunded to ratepayers.

11. Effective January 20, 1996, the revenue requirement associated with the disputed High Voltage Direct Current Expansion

Project mechanically switched capacitor costs is no longer subject to refund.

12. Edison shall not be allowed to claim any operation and maintenance (O&M) expenses for the mechanically switched capacitor equipment until after July 2013 unless the 23-year agreement between Pacific Gas & Electric Company and Los Angeles Department of Water and Power is cancelled or modified.

13. Edison shall prepare a report on how the upgraded transmission-related equipment, such as circuit breakers, disconnect switches, transformers, etc. related to the 500 kilovolt (kV), 200kV and other substations performed during the January 17, 1994 Northridge earthquake, and what changes should be considered with respect to transmission lines and other lower voltage facilities in its Seismic Upgrade Program. Edison shall also include in its report a short discussion of its seismic damage insurance coverage, if any, for these facilities. Edison shall file this report no later than March 1, 1996 in this docket and serve it on the parties to this proceeding as well as on the Commission's Safety and Enforcement Division.

14. Edison shall consider the use of more compact designs for its new substations and lines to the extent these designs are a cost-effective means of reducing land, right-of-way, and equipment costs.

15. Beginning in 1996 and ending in 1998, Edison shall file an annual report no later than March 1 of each year indicating (1) the number of pole inspections and inspections of underground structures it has conducted in the prior year, and (2) the number of pole inspections and inspections of underground structures it forecasted in its general rate case testimony for that year. This report shall be filed with the Commission in this docket and served on the Commission Advisory and Compliance Division as well as all parties to this case. If at the end of any year Edison has failed to meet its targeted (i.e., forecasted) goals, we will consider

imposing penalties on Edison for compromising the safety of its distribution system.

16. After meeting and conferring with interested parties from this proceeding and its Advisory Committee, Edison shall file an Advice Letter which assigns the adopted Customer Service and Informational funding in Section 11 to the proper FERC accounts. This Advice Letter shall be filed within 60 days of the effective date of this decision. If the parties do not reach consensus, the Advice Letter shall state Edison's preference, as well as all alternative positions of other parties.

17. For all of the retrofit programs, Edison shall not implement demand-side management (DSM) measures that are not cost effective at the end use level. Edison shall (1) update its cost effectiveness tests using adopted electric avoided costs and (2) demonstrate that the measures it plans to pursue pass the total resource cost (TRC) and utility cost tests (UC test) consistent with our DSM rules. Edison shall file this update as an Advice Letter within 60 days of the effective date of this decision. Funds for these programs will receive two-way balancing account treatment.

18. For all of the new construction programs, Edison should (1) update its cost effectiveness tests using adopted electric avoided costs and (2) demonstrate that the program it plans to pursue passes the TRC and UC tests consistent with our DSM rules. Edison shall file this update as an Advice Letter within 60 days of the effective date of this decision. Funds for these programs will receive two-way balancing account treatment.

19. Edison shall establish a two-way balancing account for its retrofit and new construction programs in order to implement its funding flexibility.

20. When determining funding priority, Edison shall work with low-income representatives to determine which types of programs best assist low-income customers in managing their energy bills.

21. Edison is authorized to carry over funds directed to DSM Bidding to meet commitments beyond the rate case cycle should they occur. Funding for both the residential and nonresidential DSM billing levels is for three years only (i.e., from 1995-1997).

22. Within the funds we have authorized for nonresidential Energy Management Services activities, Edison shall continue to offer service and audits to all customer groups, investigate additional approaches to achieve energy efficiency in the nonresidential market, as well as provide Major Customer Contact services.

23. Edison shall return the carryover funding it received to meet additional need for low-income services in 1995 authorized in Resolution E-3414, to ratepayers. Edison shall file a report within 60 days of the effective date of this decision setting forth how it has returned the carryover funding to the ratepayers.

24. Edison shall not adopt the Barrington Wellesley Group (BWG) recommendation concerning the General Auditor but shall adopt all of BWG's other outstanding financial and management/policy recommendations as set forth in Section 15.

25. Edison shall return all revenues recorded in the royalty memorandum account for its 1992 general rate case cycle to ratepayers by an Advice Letter filing on or before March 31, 1996. Edison shall return all revenues recorded in the royalty memorandum account for the 1995 general rate case cycle to ratepayers by an Advice Letter filing on or before March 31, 1998.

26. Edison's proposed changes to Tariff Rule 2, Section H are adopted. Because we address and approve these changes today, these changes shall not be retroactive to January 1, 1995.

27. An adder value of 0.53 mills/kilowatt-hour (kWh) shall be applied prospectively for the ratemaking treatment for each kWh of off-system sales delivered after January 1, 1995, subject to our discussion of RECLAIM in Section 16. Edison's revenue requirements

shall be reduced by 1,595 gigawatt-hour (the off-system sales forecast) times 0.53 mills/kWh.

28. Edison shall credit retail ratepayers for the value of RECLAIM trading credits which are consumed in making off-system sales. This credit will be based on the value Edison will implement in its system dispatch computer to reflect the value of RECLAIM trading credits for purposes of making transaction decisions. Implementation shall occur no later than January 20, 1996. The value of RECLAIM trading credits shall be credited to ratepayers before any recovery of variable/incremental O&M costs by shareholders.

29. Edison shall terminate entries to the memorandum account established by Resolution E-3369 after sales delivered through December 31, 1994 are recorded, and shall recover any ending amounts based on the adopted adder of 0.53 mills/kWh, and the difference between forecast and recorded off-system sales.

30. Edison shall not be authorized to file an Advice Letter seeking attrition year increases.

31. If Edison believes that extraordinary circumstances arise which require rate increases before a form of performance-based ratemaking is implemented, Edison shall file an application (not an Advice Letter) to make this request with specificity and to state how the request is compatible with its other requests and our other pending proceedings.

32. No later than February 29, 1996, Edison shall quantitatively demonstrate in this proceeding that all components of its streetlight acquisition program's revenue requirement (including return on rate base, franchise fees and uncollectibles, etc.) will be borne only by participating LS-1 customers (and to take appropriate corrective rate design measures as needed). If the filing is contested, the issue should be resolved in Edison's next rate design window proceeding or other appropriate forum as determined by the assigned ALJ.

33. Edison shall file its flexible refueling outage schedule request as an Advice Letter in attrition years using test year values of O&M expenses for refueling. Edison shall not expand this filing to include other items not previously included in the flexible refueling outage schedule request.

34. Edison shall establish a one-way balancing account for all economic development funds authorized in today's decision.

This order is effective today.

Dated January 10, 1996, at San Francisco, California.

DANIEL Wm. FESSLER
President
GREGORY CONLON
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

LIST OF ACRONYMS

A. - Application

A&G - Administrative and General

ACS - Advanced Computing Systems

AEAP - Annual Earnings Assessment Proceeding

AFUDC - Allowance For Funds Used During Construction

AIR - Advanced Integrated Recycling

ALBRR - Authorized Level of Base Rate Revenue

ALJ - Administrative Law Judge

APL - Authorized Payment Location

APS - Advanced Photovoltaic Systems Inc.

AR - Accounting Release

ARCA - The Appliance Recycling Centers of America, Inc.

Ascension - Ascension Technology, Inc.

ASDC - Application Software Development Costs

Bechtel - Bechtel Corporation

BLS - Bureau of Labor Statistics

Btu - British Thermal Unit

BWG - Barrington Wellesley Group

CAC - Cogeneration Association of California

CACD - Commission Advisory and Compliance Division

Cal/Neva - California/Nevada Community Action Association

CALPERS - California Public Employees' Retirement System

CAL-SLA - California City-County Street Light Association

CARE - California Alternate Rates for Energy

CBM - Condition Based Maintenance

CBOs - Community-Based Organizations

CCC - California Cogeneration Council

CEC - California Energy Commission

CEERT - Center for Energy Efficiency and Renewable Technology

CEMA - Catastrophic Event Memorandum Account

CFB - Compact Fluorescent Bulbs

CFL - Compact Fluorescent Lamps

CIA - Commercial, Industrial and Agricultural

CIEE - California Institute for Energy Efficiency

CLECA - California Large Energy Consumers Association

CMA - California Manufacturers Association

COT Project - California Oregon Transmission Project

CPCN - Certificate of Public Convenience and Necessity

CSB - Cogeneration Service Bureau

CSEI - California Solar Energy Industries Association

CS&I - Customer Service and Informational

CTAC - Customer Technology Application Center

D. - Decision

DAP - Direct Assistance Program

DGS - California Department of General Services

D&O - Directors and Officers

APPENDIX A
Page 3

DOE - United States Department of Energy

DRA - Division of Ratepayer Advocates

DRI - Data Resources Incorporated

DSM - Demand-side Management

ECAC - Energy Cost Adjustment Clause

ECIBPNS - Employer Cost Index for All Pensions and Benefits

Edison - Southern California Edison Company

EEI - Edison Electric Institute

EMF - Electromagnetic Fields

EMS - Energy Management Services

ERAM - Electric Revenue Adjustment Mechanism

EPRI - Electric Power Research Institute

Farm Bureau - California Farm Bureau Federation

FEA - Federal Executive Agencies

FERC - Federal Energy Regulatory Commission

GRC - General Rate Case

GOR - Gross Operating Revenue

gWh - Gigawatt hour

HMO - Health Maintenance Organization

I. - Investigation

ICA - Insulation Contractors Association

ICIP - Incremental Cost Incentive Pricing

IEP - Independent Energy Producers Association

Intervenor Unions - Local 47 of the International Brotherhood of Electrical Workers, AFL-CIO and Local 246 of the Utility Workers Union of America, AFL-CIO

IPP - Independent Power Providers

IPCs - Intermediate Processing Centers

IU - Industrial Users

kV - Kilovolt

LADWP - Los Angeles Department of Water and Power

LEV - Low-Emission Vehicle

LIRA -Low Income Ratepayer Assistance

MFRR - Measurement, Forecasting and Regulatory Reporting

MW - megawatt

NARUC - National Association of Utility Regulatory Commissioners

NEEI - Nonresidential Energy Efficiency Incentives

NLRA - National Labor Relations Act

NMRC - Nuclear Management and Resource Council

NOI - Notice of Intent

NRDC - Natural Resources Defense Council

NUIP - Nuclear Unit Incentive Procedure

O&M - Operation and Maintenance

OPSIM - Off-system Power Sales Incentive Mechanism

PBOP - Post-Retirement Benefits Other Than Pensions

PBR - Performance-Based Ratemaking

PG&E - Pacific Gas and Electric Company

PHC - Prehearing Conference

PMRC - Plant Modification Review Committee

PU - Public Utilities

PV - Photovoltaic

PVNGS - Palo Verde Nuclear Generating Station

QF - Qualifying Facility

R. - Rulemaking

RAEI - Residential Appliance Efficiency Incentives

RBFs - Request for Bids

RD&D - Research, Development and Demonstration

RIM - Ratepayer Impact Measure

R.O. - Regulated Output

R.T. - Reporter's Transcript

RTUs - Remote Terminal Units

SCAQMD - South Coast Air Quality Management District

SCAG - Southern California Association of Governments

SDG&E - San Diego Gas & Electric Company

SEIA - Solar Energy Industries Association

SMUD - Sacramento Municipal Utility District

SoCalGas - Southern California Gas Company

SONGS - San Onofre Nuclear Generating Station

SRA - Schedule of Ruling Amounts

SRAC - Short-Run Avoided Cost

T&D - Transmission and Distribution

APPENDIX A
Page 6

TP&D - Technology Planning and Development

Trade and Commerce Agency - California Trade & Commerce Agency

TRC - Total Resource Cost

TURN - Toward Utility Rate Normalization

UC - University of California

UC Test - Utility Cost Test

UCS - Union of Concerned Scientists

UPVG - Utility Photovoltaic Group

Vol. - Volume

WEST - Western Energy Supply and Transmission

WMA - Western Mobilehome Parkowners Association

WMS - Work Management System

(END OF APPENDIX A)

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
Authorized Level of Base Rate Revenue (ALBRR)
Effective January 20, 1996

	GRC ALBRR	$ (000)	References
1	GRC ALBRR as of 1/1/95	3,848,238	D.94-12-045
2	Palo Verde Adjustment	(272)	D.95-05-042
3	Settlement ALBRR	3,847,966	As filed 11/16/94
4	CEMA Correction	(343)	Exhibit 255
5	Corrected Settlement ALBRR	3,847,623	Exhibit 255
6	Adopted GRC ALBRR	3,838,556	Appendix B, Page 3
7	1995 Adopted GRC Adjustment	(9,067)	Line 6 - Line 5
	Total ALBRR	**$ (000)**	**References**
8	Total ALBRR as of 1/1/95	4,115,105	D.94-12-045
9	Palo Verde Adjustment	(272)	D.95-05-042
10	CEMA Correction	(352)	Exhibit 255
11	SONGS 1 Annual Adj	(11,681)	D.92-08-036
12	1996 Cost of Capital	(53,069)	D.95-11-062
13	1996 Cost of Capital Adj	22	1/
14	ACRA/RCRA Annual Adj	391	D.94-06-068
15	1995 Adopted GRC Adj	(9,067)	Line 7
16	Nuclear Refueling Adj	(24,118)	Appendix D, Page 33
17	Franchise Fee Rate Adj	(74)	2/
18	Adopted Total ALBRR	4,016,886	

1/ Reflects differences in authorized rate base and net-to-gross multiplier between interim (D.94-12-045) and final decisions.

2/ Impact of adopted franchise fee rate on non-GRC portion of 1/1/95 total ALBRR.

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
SUMMARY OF EARNINGS
AT ADOPTED RATES - Total System
(Thousands of 1995 Dollars)

ITEM	AUTHORIZED 12/31/94	SETTLEMENT	ADOPTED 1/1/96	DIFFERENCE
	(1)	(2)	(3)	(2)-(3)
OPERATING REVENUES	$3,920,950	$3,860,041	$3,850,904	($9,137)
OPERATING EXPENSES				
Steam	242,893	215,302	214,745	(557)
Nuclear	226,224	261,692	261,095	(597)
Hydro	23,167	26,007	25,234	(773)
Other	21,539	18,649	18,601	(48)
Subtotal - Production	513,823	521,650	519,675	(1,975)
Transmission	82,993	79,449	78,465	(984)
Distribution	194,412	180,408	179,744	(664)
Customer Accounts	130,051	136,845	136,308	(537)
Uncollectibles	8,156	14,758	13,141	(1,617)
CS&I - DSM-Related	149,233	51,000	69,293	18,29[illegible]
- Non-DSM-Related	0	26,024	13,728	(12,29[illegible]
RD&D - RD&D-Related	55,193	27,700	29,728	2,028
- O&M-Related	0	500	498	(2)
A&G (Except RD&D, P&B)	206,239	225,307	217,787	(7,520)
Health Care	127,065	165,950	154,366	(11,584)
Non-Health Care 1/	70,766	73,435	72,880	(555)
Franchise Requirements	30,885	32,328	31,142	(1,186)
Software Savings	0	(3,455)	(7,386)	(3,931)
Compensation Adj	0			
Off-System Sales 2/	1,915			
Revenue Credits	(106,952)	(147,523)	(132,303)	15,220
Subtotal	$1,463,779	$1,384,376	1,376,221	(8,155)
Depreciation	700,134	730,560	730,431	(129)
Nuclear Decomm. Exp.	95,069	99,822	99,822	0
Taxes Other than Income	194,460	200,746	199,120	(1,626)
Taxes on Income	449,073	432,448	432,774	326
Total Operating Exp.	$2,902,515	$2,847,952	2,838,368	(9,584)
NET OPERATING REVENUE	$1,018,435	$1,012,089	1,012,536	447
RATE BASE	11,163,289	11,041,475	11,041,827	352
RATE OF RETURN	9.12%	9.17%	9.17%	

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
SUMMARY OF EARNINGS
AT ADOPTED RATES - CPUC Jurisdiction
(Thousands of 1995 Dollars)

ITEM	AUTHORIZED 12/31/94	SETTLEMENT	ADOPTED 1/1/96	DIFFERENCE
	(1)	(2)	(3)	(3)-(2)
OPERATING REVENUES	$3,915,543	$3,847,623	$3,838,556	($9,067)
OPERATING EXPENSES				
Steam	242,166	214,094	213,534	(560)
Nuclear	225,585	260,202	259,623	(579)
Hydro	23,101	25,861	25,092	(769)
Other	21,519	18,549	18,496	(53)
Subtotal - Production	512,371	518,706	516,744	(1,962)
Transmission	82,902	79,255	78,274	(981)
Distribution	194,285	180,227	179,564	(663)
Customer Accounts	130,026	136,821	136,284	(537)
Uncollectibles	8,137	14,758	13,141	(1,617)
CS&I - DSM-Related	149,232	51,000	69,293	18,293
- Non-DSM-Related	0	26,024	13,728	(12,296)
RD&D - RD&D-Related	55,108	27,622	29,644	2,022
- O&M-Related	0	499	497	(2)
A&G (Except RD&D, P&B)	205,934	224,672	217,173	(7,499)
Health Care	126,877	165,482	153,930	(11,552)
Non-Health Care	70,664	73,228	72,674	(554)
Franchise Requirements	30,826	32,224	31,042	(1,182)
Software Savings	0	(3,445)	(7,365)	(3,920)
Compensation Adj	0	0	0	0
Off-System Sales	1,912	0	(843)	
Revenue Credits	(106,869)	(147,372)	(132,169)	15,203
Subtotal	$1,461,405	$1,379,709	1,371,613	(8,096)
Depreciation	699,292	728,285	728,156	(129)
Nuclear Decomm. Exp.	94,955	99,258	99,259	1
Taxes Other than Income	194,192	200,115	198,496	(1,619)
Taxes on Income	449,121	431,491	431,816	325
Total Operating Exp.	$2,898,964	$2,838,850	2,829,340	(9,510)
NET OPERATING REVENUE	$1,016,579	$1,008,773	1,009,216	443
RATE BASE	11,148,561	11,005,278	11,005,629	351
RATE OF RETURN	9.12%	9.17%	9.17%	

(END OF APPENDIX B)

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
SUMMARY OF EARNINGS
AT ADOPTED RATES - CPUC Jurisdiction
(Thousands of 1995 Dollars)

ITEM	AUTHORIZED 12/31/94	SETTLEMENT	ADOPTED 1/1/96	DIFFERENCE
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Nuclear	225,585	260,202	259,623	(579)
Hydro	23,101	25,861	25,092	(769)
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Subtotal - Production	512,371	518,706	516,744	(1,962)
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Distribution	194,285	180,227	179,564	(663)
Customer Accounts	130,026	136,821	136,284	(537)
Uncollectibles	8,137	14,758	13,141	(1,617)
CS&I - DSM-Related	149,232	51,000	69,293	18,293
- Non-DSM-Related	0	26,024	13,728	(12,296)
RD&D - RD&D-Related	55,108	27,622	29,644	2,022
- O&M-Related	0	499	497	(2)
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Non-Health Care	70,664	73,228	72,674	(554)
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Software Savings	0	(3,445)	(7,365)	(3,920)
Compensation Adj	0	0	0	0
Off-System Sales	1,912	0	(843)	
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Subtotal	$1,461,405	$1,379,709	1,371,613	(8,096)
Depreciation	699,292	728,285	728,156	(129)
Nuclear Decom. Exp.	94,955	99,258	99,259	1
Taxes Other than Income	194,192	200,115	198,496	(1,619)
Taxes on Income	449,121	431,491	431,816	325
Total Operating Exp.	$2,898,964	$2,838,850	2,829,340	(9,510)
NET OPERATING REVENUE	$1,016,579	$1,008,773	1,009,216	443
RATE BASE	11,148,561	11,005,278	11,005,629	351
RATE OF RETURN	9.12%	9.17%	9.17%	

(END OF APPENDIX B)

APPENDIX C

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
ADOPTED SALES AND CUSTOMER FORECASTS

Forecast	Settlement (b)	Adopted (c)
Sales Forecast (GWh)		
Five CPUC Major Revenue Classes		
Residential	23,000	23,000
Commercial	28,380	28,380
Industrial	13,480	13,480
Other Public Authority 1/	6,170	6,170
Agricultural	1,040	1,040
Subtotal	72,070	72,070
Total Sales Forecast	72,070	72,070
Customer Forecast (No. of Customers)		
Five CPUC Major Revenue Classes		
Residential	3,692,996	3,692,996
Commercial	387,780	387,780
Industrial	29,248	29,248
Other Public Authority 1/	45,140	45,140
Agricultural	25,176	25,176
Subtotal	4,180,340	4,180,340
Total Customer Forecast	4,180,340	4,180,340

1/ Includes Streetlighting class.

APPENDIX C

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
ADOPTED ESCALATION RATES
(Base Year 1992)

Year	Labor Rate	Labor Index	Nonlabor Rate	Nonlabor Index
1992	--	100.00	--	100.00
1993	3.25%	103.25	2.55%	102.55
1994	3.25%	106.61	2.60%	105.22
1995	2.63%	109.41	3.14%	108.52

Note: To implement the 1995 managerial/ administrative employee wage freeze reduction (Section 19.3.2 of text), the 1995 labor rate is adjusted as shown in Appendix D, Page 30.

(END OF APPENDIX C)

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995

RESULTS OF OPERATION DETAIL

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APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
CALCULATION OF FRANCHISE FEES AND UNCOLLECTIBLES
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Description	Adopted
Uncollectibles	
Adopted Base Revenue - CPUC	$3,838,556
Uncollectible Rate	0.3130%
Uncollectible Base Revenue	12,015
Uncollectible Other Operating Revenue	1,127
Total Uncollectibles	13,141
Franchise Fees	
Adopted Base Revenue - Total System	$3,850,904
Franchise Fee Rate	0.8087%
Total Franchise Fees	$31,142

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
TOTAL PRODUCTION EXPENSE
(Thousands Of 1992 Dollars Unless Otherwise Indicated)

Description	Adopted
Operation	
Steam	$84,250
Nuclear	150,155
Hydroelectric	11,107
Other	6,328
Total Operation	$251,840
Maintenance	
Steam	114,118
Nuclear	90,239
Hydroelectric	12,123
Other	10,796
Total Maintenance	$227,276
TOTAL PRODUCTION (1992$)	$479,116
Escalation Amounts, 1992 to 1995	
Labor	17,116
Non-Labor	23,443
Other	0
Total	$40,559
TOTAL PRODUCTION (1995$)	$519,675

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
STEAM PRODUCTION EXPENSE
(Thousands Of 1992 Dollars Unless Otherwise Indicated)

Account	Description	Adopted
	Operation	
500.0	Supervision and Engineering	$11,981
501.0	Fuel Related Expenses	25,116
502.0	Steam Expenses	24,289
505.0	Electric Expenses	7,637
506.0	Misc. Steam Power Expenses	14,959
507.0	Rents	268
	Total Operation	$84,250
	Maintenance	
510.0	Supervision and Engineering	23,278
511.0	Structures	5,767
512.0	Boiler Plant	42,254
513.0	Electric Plant	20,564
514.0	Miscellaneous Steam Plant	22,255
	Total Maintenance	$114,118
	TOTAL STEAM PRODUCTION (1992$)	$198,368
	Escalation Amounts 1992 to 1995	
	Labor	7,515
	Non-Labor	8,862
	Other	0
	Total	$16,377
	TOTAL STEAM PRODUCTION (1995$)	$214,745

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
NUCLEAR PRODUCTION EXPENSE
(Thousands Of 1992 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted 1/
	Operation	
517	Supervision and Engineering	$47,821
519	Coolants and Water	6,224
520	Steam Expenses	24,126
523	Electric Expenses	3,152
524	Misc. Nuclear Power Expenses	67,819
525	Rents	1,013
	Total Operation	$150,155
	Maintenance	
528	Supervision and Engineering	18,675
529	Structures	14,070
530	Reactor Plant Equipment	29,157
531	Electric Plant	12,976
532	Miscellaneous Nuclear Plant	15,361
	Total Maintenance	$90,239
	TOTAL NUCLEAR PROD. (1992$)	$240,394
	Escalation Amounts 1992 to 1995	
	Labor	8,037
	Non-Labor	12,664
	Other	0
	Total	$20,701
	TOTAL NUCLEAR PROD. (1995$)	$261,095

1/ Reflects 2 refueling outages for SONGS and 3 for Palo Verde during 1995; data on average cost per outage given in Appendix D, Page 33.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
HYDROELECTRIC PRODUCTION EXPENSE
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
535.0	Supervision and Engineering	$2,123
536.0	Water for Power	2,317
537.0	Hydroelectric Expenses	1,930
538.0	Electric Expense	1,840
539.0	Misc. Hydro Expense Generation	2,123
540.0	Rents	774
	Total Operation	$11,107
	Maintenance	
541.0	Supervision and Engineering	1,903
542.0	Structures	1,694
543.0	Reservoirs, Dams and Waterways	1,872
544.0	Maintenance of Electric Plant	4,084
545.0	Miscellaneous Hydroelectric Plant	2,570
	Total Maintenance	$12,123
	TOTAL HYDRO PRODUCTION (1992$)	$23,230
	Escalation Amounts, 1992 to 1995	
	Labor	913
	Non-Labor	1,091
	Other	0
	Total	$2,004
	TOTAL HYDRO PRODUCTION (1995$)	$25,234

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
OTHER POWER PRODUCTION EXPENSE
(Thousands Of 1992 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
546.0	Supervision and Engineering	$1,649
548.0	Generation Expenses	3,753
549.0	Misc. Other Power Expenses	926
550.0	Rents	0
	Total Operation	$6,328
	Maintenance	
551.0	Supervision and Engineering	1,832
552.0	Maintenance of Structures	761
553.0	Maintenance of Electric Plant	6,237
554.0	Misc. Other Power Gen. Plant	1,966
	Total Maintenance	$10,796
	TOTAL OTHER PRODUCTION (1992$)	$17,124
	Escalation Amounts, 1992 to 1995	
	Labor	651
	Non-Labor	825
	Other	0
	Total	$1,477
	TOTAL OTHER PRODUCTION (1995$)	$18,601

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
TRANSMISSION EXPENSE
(Thousands Of 1992 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
560.0	Supervision and Engineering	$7,247
561.0	Load Dispatching	8,961
562.0	Station Expenses	17,547
563.0	Overhead Line Expenses	1,088
564.0	Underground Line Expenses	187
565.0	Trans. of Elect. By Others	3,188
566.0	Misc. Transmission Expenses	6,256
567.0	Rents	654
	Total Operation	$45,128
	Maintenance	
568.00	Supervision and Engineering	3,921
569.00	Structures	2,050
570.00	Station Equipment	8,688
571.00	Overhead Lines	9,611
572.00	Underground Lines	81
573.00	Misc. Transmission Plant	2,982
	Total Maintenance	$27,333
	TOTAL TRANSMISSION (1992$)	$72,461
	Escalation Amounts, 1992 to 1995	
	Labor	3,731
	Non-Labor	2,273
	Other	0
	Total	$6,004
	TOTAL TRANSMISSION (1995$)	$78,465

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
DISTRIBUTION EXPENSE
(Thousands Of 1992 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
580.0	Supervision and Engineering	$20,402
582.0	Station Expenses	10,619
583.0	Overhead Line Expenses	7,633
584.0	Underground Line Expenses	2,585
585.0	Street Lighting & Signal Sys	837
586.0	Meter Expenses	16,207
587.0	Customer Installations	14,443
588.0	Misc. Distribution Expenses	16,021
589.0	Rents	2,120
	Total Operation	$90,867
	Maintenance	
590.00	Supervision and Engineering	9,820
591.00	Structures	2,578
592.00	Station Equipment	5,373
593.00	Overhead Services	23,261
594.00	Underground Lines	10,282
595.00	Line Transformers	2,395
596.00	Street Lighting & Signal Sys	2,546
597.00	Meters	1,674
598.00	Misc. Distribution Plant	16,611
	Total Maintenance	$74,540
	TOTAL DISTRIBUTION (1992$)	$165,407
	Escalation Amounts, 1992 to 1995	
	Labor	8,942
	Non-Labor	5,395
	Other	0
	Total	$14,337
	TOTAL DISTRIBUTION (1995$)	$179,744

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
CUSTOMER ACCOUNTS EXPENSE
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
901.0	Supervision	$12,076
902.0	Meter Reading Expenses	25,519
903.0	Customer Records and Collectibles	85,483
904.0	Uncollectible Accounts	13,141
905.0	Misc. Customer Accounts Exp.	3,506
	TOTAL CUSTOMER ACCTS (1992$)	$139,725
	Total (Less Uncollectibles)	$126,584
	Escalation Amounts 1992 to 1995	
	Labor	7,221
	Non-Labor	2,503
	Other	0
	Total	$9,724
	TOTAL CUSTOMER ACCTS (1995$)	$149,449
	Total (Less Uncollectibles)	$136,308

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Residential & Non-Residential Conservation, Service Planning, and Load Management Expenses	
907, 908 & 909	DSM Balancing Account	65,800
	Non-DSM O&M	12,639
	TOTAL CUSTOMER SERVICES AND INFORMATIONAL (1992$)	$78,439
	Escalation Amounts 1992 to 1995	
	Labor	1,765
	Non-Labor	2,818
	Other	0
	Total	$4,583
	TOTAL CUSTOMER SERVICES AND INFORMATIONAL (1995$)	$83,022

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
ADMINISTRATIVE & GENERAL EXPENSES
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
920.0	Administrative & Gen. Salaries	$116,394
921.0	Office Supplies and Expenses	32,022
922.0	Admin. & Gen. Transfer Credit	(26,715)
923.0	Outside Services Employed	4,065
924.0	Property Insurance	12,628
925.0	Injuries and Damages	29,569
926.0	Pensions and Benefits-Total	226,118
	Pensions & Benefits-Health Care $154,206	
	Pensions & Benefits-Non-Health C. 71,912	
927.0	Franchise Requirements	31,142
928.0	Regulatory Commission Expenses	5,041
930.0	Misc. General Expenses-Total	38,772
930.1	General Advt. Expense 618	
930.2	Other Misc. General Expenses 38,154	
	- RD&D 27,923	
931.0	Rents	4,029
	Total Operation	$473,065
	Maintenance	
935.0	Maintenance of General Plant	15,088
	Total Maintenance	15,088
	TOTAL ADMIN. & GEN. (1992$)	$488,153
	Total (Less Franchise Req.)	$457,011
	Escalation Amounts, 1992 to 1995	
	Labor	10,254
	Non-Labor	7,994
	Other	0
	Total	$18,248
	TOTAL ADMIN. & GEN. (1995$)	$506,401
	Total (Less Franchise Req.)	$475,259

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
EXPENSE SUMMARY
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Description		Adopted
TOTAL NON-ESCALATED		
Steam Production	$198,368	
Nuclear Production	240,394	
Hydroelectric Production	23,230	
Other Production	17,124	
Total Production		$479,116
Transmission		72,461
Distribution		165,407
Customer Accounts		139,725
Customer Service & Informational		78,439
Administrative and General		488,153
Additional Productivity		0
Total Non-Escalated (1992$)		$1,423,301
TOTAL ESCALATED		
Steam Production	214,745	
Nuclear Production	261,095	
Hydroelectric Production	25,234	
Other Production	18,601	
Total Production		$519,675
Transmission		78,465
Distribution		179,744
Customer Accounts		149,449
Customer Service & Informational		83,022
Administrative and General		506,401
Additional Productivity		0
Total Escalated (1995$)		$1,516,755
TOTAL ESCALATION (1992$ to 1995$)		
Steam Production	16,377	
Nuclear Production	20,701	
Hydroelectric Production	2,004	
Other Production	1,477	
Total Production		$40,559
Transmission		6,004
Distribution		14,337
Customer Accounts		9,724
Customer Service & Informational		4,583
Administrative and General		18,2[illegible]
Additional Productivity		[illegible]
Total Escalation		$93,454

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
LABOR SUMMARY
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Description	Adopted
LABOR NON-ESCALATED (1992$)	
Steam Production	$85,793
Nuclear Production	91,754
Hydroelectric Production	10,421
Other Production	7,437
Total Production	$195,405
Transmission	42,595
Distribution	102,089
Customer Accounts	82,434
Customer Service & Informational	20,150
Administrative and General	117,059
Additional Productivity	0
Total Non-Escalated Labor	$559,732
LABOR ESCALATED (1995$)	
Steam Production	93,308
Nuclear Production	99,791
Hydroelectric Production	11,334
Other Production	8,088
Total Production	$212,521
Transmission	46,326
Distribution	111,031
Customer Accounts	89,655
Customer Service & Informational	21,915
Administrative and General	127,313
Additional Productivity	0
Total Escalated Labor	$608,761
LABOR ESCALATION (1992$ to 1995$)	
Steam Production	7,515
Nuclear Production	8,037
Hydroelectric Production	913
Other Production	651
Total Production	$17,116
Transmission	3,731
Distribution	8,942
Customer Accounts	7,221
Customer Service & Informational	1,765
Administrative and General	10,254
Additional Productivity	0
Total Labor Escalation	$49,029

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
NON-LABOR SUMMARY
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Description	Adopted
NON-LABOR NON-ESCALATED (1992$)	
Steam Production	$104,014
Nuclear Production	148,640
Hydroelectric Production	12,809
Other Production	9,687
Total Production	$275,150
Transmission	26,678
Distribution	63,318
Customer Accounts	29,376
Customer Service & Informational	33,073
Administrative and General	93,829
Additional Productivity	0
Total Non-Escalated Non-Labor	$521,424
NON-LABOR ESCALATED (1995$)	
Steam Production	112,876
Nuclear Production	161,304
Hydroelectric Production	13,900
Other Production	10,512
Total Production	$298,593
Transmission	28,951
Distribution	68,713
Customer Accounts	31,879
Customer Service & Informational	35,891
Administrative and General	101,823
Additional Productivity	0
Total Escalated Non-Labor	$565,849
NON-LABOR ESCALATION (1992$ to 1995$)	
Steam Production	8,862
Nuclear Production	12,664
Hydroelectric Production	1,091
Other Production	825
Total Production	$23,443
Transmission	2,273
Distribution	5,395
Customer Accounts	2,503
Customer Service & Informational	2,818
Administrative and General	7,994
Additional Productivity	0
Total Non-Labor Escalation	$44,425

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
OTHER SUMMARY
(Thousands of 1992 Dollars Unless Otherwise Indicated)

Description	Adopted
OTHER NON-ESCALATED (1992$)	
Steam Production	$8,561
Nuclear Production	0
Hydroelectric Production	0
Other Production	0
Total Production	$8,561
Transmission	3,188
Distribution	0
Customer Accounts	27,915
Customer Service & Informational	25,216
Administrative and General	277,265
Additional Productivity	0
Total Non-Escalated Other	$342,145
OTHER ESCALATED (1995$)	
Steam Production	8,561
Nuclear Production	0
Hydroelectric Production	0
Other Production	0
Total Production	$8,561
Transmission	3,188
Distribution	0
Customer Accounts	27,915
Customer Service & Informational	25,216
Administrative and General	277,265
Additional Productivity	0
Total Escalated Other	$342,145
OTHER ESCALATION (1992$ to 1995$)	
Steam Production	0
Nuclear Production	0
Hydroelectric Production	0
Other Production	0
Total Production	$0
Transmission	0
Distribution	0
Customer Accounts	0
Customer Service & Informational	0
Administrative and General	0
Additional Productivity	0
Total Other Escalation	$0

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
TAXES OTHER THAN ON INCOME
(Thousands of 1995 Dollars)

Description	Adopted
Ad Valorem Taxes	
Ca., Ariz., N.M., Nev. & D.C.	$146,460
Total Ad Valorem Taxes	146,460
Payroll Taxes	
Federal Insurance Contrib. Act (FICA)	49,128
Federal Unemployment Insurance	235
State Unemployment Insurance	2,199
Total Payroll Taxes	51,562
Miscellaneous Taxes	
Superfund Tax	1,333
Miscellaneous Taxes	(235)
Total Miscellaneous Taxes	1,098
Total Taxes OTOI (1992$)	$199,120
Superfund Tax Calculation	
Federal Taxable Income (excl. Superfund Tax)	$922,707
Plus:	
Deprec-Tangible Personal Property	108,614
ACE Adjustment	81,360
Tax Preferences	30
Alt. Min. Taxable Income	1,112,711
Superfund Exclusion	(2,000)
Superfund Taxable Income	$1,110,711
Superfund Tax Rate	0.12%
Superfund Tax	$1,333

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
INCOME TAX ADJUSTMENTS
(Thousands of 1995 Dollars)

Description	Adopted
California Income Tax Adjustments	
Tax Depreciation (liberalized)	$741,828
Nuclear Fuel Amort. (liberalized)	(59,228)
Fuel Oil Transp. Fac. (liberalized)	(7,650)
Interest on Long-Term Debt	393,089
Interest on Accumulated ITC	(13,443)
CIAC Revenues	(31,861)
Non-Deductible Business Meals	(1,003)
Ad Valorem Lien Date Adjust.	1,629
Removal Costs	36,000
Right of Way Easement Amort.	2,458
Repair Allowance	35,000
Salvage Warehouse Exp.	530
ACE Limited Insurance	0
Superfund Tax (ACE)	(1,333)
Uniform Capitalization	(16,559)
Capitalized Software	27,869
RD&D	(5,109)
Excess Compensation/Leased Vehicles	(348)
	$1,101,868
Federal Income Tax Adjustments	
Tax Depreciation (liberalized)	813,455
Nuclear Fuel Amort. (liberalized)	(59,228)
Fuel Oil Transp. Fac. (liberalized)	(7,650)
Interest on Long-Term Debt	393,089
CIAC Taxable Income	(15,784)
Non-Deductible Business Meals	(1,003)
Ad Valorem Lien Date Adjust.	1,629
Removal Costs	11,000
Right of Way Easement Amort.	2,430
Repair Allowance	22,000
Salvage Warehouse Exp.	530
ACE Limited Insurance	0
Preferred Dividend Credit	809
Uniform Capitalization	(16,559)
Capitalized Software	27,869
RD&D	(5,109)
Excess Compensation/Leased Vehicles	(348)
	$1,167,130

APPENDIX D
SOUTHERN CALIFORNIA EDISON COMPANY - Total System
Test Year 1995
TAXES ON INCOME - ADOPTED RATES

Description		Adopted
California Corporation Franchise Tax		
Operating Revenues		$3,850,904
Operating Expenses		1,376,221
Nuclear Decommissioning Exp.(Qualified)		95,444
Taxes Other Than on Income		199,120
State Income Tax Adjustments		1,101,868
California Taxable Income		$1,078,251
CCFT Tax Rate		8.656%
TOTAL CCFT		$93,334
Federal Income Tax		
Operating Revenues		$3,850,904
Operating Expenses		1,376,221
Nuclear Decommissioning Exp.(Qualified)		95,444
Taxes Other Than on Income		199,120
CCFT--Privilege Year Minus Current Year		(5,403)
State Income Taxes		97,018
Federal Income Tax Adjustments		1,167,130
Federal Taxable Income		$921,374
FIT Tax Rate		35.00%
Federal Income Tax		$322,481
Ariz. & NM State Income Tax		
California Taxable Income		$1,078,251
Arizona Tax Rate		0.2647%
New Mexico Tax Rate		0.0769%
Total Rate		0.3416%
Ariz. & NM Income Tax		$3,683
Income Tax Deferred		33,937
Investment Tax Credit - Deferred		(20,661)
Total Taxes on Income		$432,774
Superfund Tax Calculation		
Federal Taxable Income (excl. Superfund Tax)		$922,707
Plus: Adjustments		188,004
Superfund Taxable Income		$1,110,711
Superfund Tax	0.12%	$1,333

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
DEPRECIATION EXPENSE
(Thousands of 1995 Dollars)

Description	Adopted
Depreciation Expense	
Steam Production	$71,844
Nuclear Production	181,588
Hydroelectric Production	12,426
Other Production	7,115
Transmission	60,391
Distribution	241,645
General	144,645
Experimental Plant	852
Subtotal	$720,505
Deferred Debit	
Nuclear decommissioning	2,939
Capitalized Software	99,822
DSM Capital Program	6,987
	0
Total Depreciation Expense	$830,253

Depreciation Expense Charged to Other Accounts

Other Depreciation (General)	1,761
Fuel Oil Transportation Facility	6,462
Total Depreciation Expense	$8,223

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
DEPRECIATION RESERVE
(Thousands of 1995 Dollars)

Description	Adopted
Depreciation Reserve - Wtd. Avg.	
Steam Production	$1,521,857
Nuclear Production	1,781,390
Hydroelectric Production	181,399
Other Production	250,520
Transmission	973,079
Distribution	2,176,675
General	432,501
Experimental Plant	10,890
Subtotal	$7,328,312
Retirement Work-in-Progress	(8,961)
Other Depreciable	
Other Depr. (General)	3,796
Fuel Oil Transp. Facilities	85,706
Total Depreciation Reserve: Wtd. Avg.	$7,408,853

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
PLANT IN SERVICE - EOY
(Thousands of 1995 Dollars)

Description	Adopted
Plant in Service - BOY	
Intangible	$113
Production Plant	
Steam	2,434,005
Nuclear	5,528,205
Hydroelectric	613,122
Other	436,874
Total Production	$9,012,206
Transmission Plant	2,744,351
Distribution Plant	6,289,024
General Plant	1,291,388
Total Plant in Service : BOY	$19,337,082
Plant in Service Net Additions	
Intangible	$0
Production Plant	
Steam	95,793
Nuclear	113,722
Hydroelectric	8,181
Other	25,120
Total Production	$242,816
Transmission Plant	90,040
Distribution Plant	330,590
General Plant	159,988
Total Net Additions	$823,435
Plant in Service EOY	
Intangible	$113
Production Plant	
Steam	2,529,798
Nuclear	5,641,927
Hydroelectric	621,303
Other	461,994
Total Production	$9,255,022
Transmission Plant	2,834,391
Distribution Plant	6,619,614
General Plant	1,451,376
Total Plant in Service : EOY	$20,160,517

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
PLANT IN SERVICE - Weighted Average
(Thousands of 1995 Dollars)

Description	Adopted
Plant in Service - BOY	
Intangible	$113
Production Plant	
Steam	2,434,005
Nuclear	5,528,205
Hydroelectric	613,122
Other	436,874
Total Production	$9,012,206
Transmission Plant	2,744,351
Distribution Plant	6,289,024
General Plant	1,291,388
Total Plant in Service : BOY	$19,337,082
Plant in Service - Weighted Average Net Additions	
Intangible	$0
Production Plant	
Steam	26,869
Nuclear	17,042
Hydroelectric	2,762
Other	8,251
Total Production	$54,925
Transmission Plant	38,031
Distribution Plant	165,851
General Plant	65,731
Total Wtd. Avg. Net Additions	$324,537
Total Plant in Service - Weighted Average	
Intangible	$113
Production Plant	
Steam	2,460,874
Nuclear	5,545,247
Hydroelectric	615,884
Other	445,125
Total Production	$9,067,131
Transmission Plant	2,782,382
Distribution Plant	6,454,875
General Plant	1,357,119
Total Plant in Service : Wtd. Avg.	$19,661,619

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
PLANT HELD FOR FUTURE USE
(Thousands of 1995 Dollars)

Description	Adopted
Plant Held for Future Use - BOY	
Intangibles & Capitalized Software	$0
Production Plant	
Steam	0
Nuclear	0
Hydroelectric	0
Other	0
Total Production	$0
Transmission Plant	25,034
Distribution Plant	7,083
General Plant	8,245
Total Plant Held for Future Use : BOY	$40,362
PHFU - Wtd. Avg. Net Additions	
Intangibles & Capitalized Software	0
Production Plant	
Steam	0
Nuclear	0
Hydroelectric	0
Other	0
Total Production	$0
Transmission Plant	2,482
Distribution Plant	0
General Plant	552
Total Wtd. Avg. Net Additions	$3,034
Plant Held for Future Use - Weighted Average	
Intangibles & Capitalized Software	$0
Production Plant	
Steam	0
Nuclear	0
Hydroelectric	0
Other	0
Total Production	$0
Transmission Plant	27,516
Distribution Plant	7,083
General Plant	8,797
Total PHFU: Wtd. Avg.	$43,396

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
RATE BASE
(Thousands of 1995 Dollars)

Description	Adopted
FIXED CAPITAL - Weighted Average	
Plant in Service	$19,661,619
PHFU	43,396
Total Fixed Capital - Wtd. Avg.	$19,705,015
ADJUSTMENTS	
Capitalized Software	65,312
Deferred Debits	80,999
Cust. Adv. for Construction	(86,309)
Total Adjustments	$60,002
WORKING CAPITAL	
Materials & Supplies	166,307
Working Cash	52,784
Fuel Inventories	0
Total Working Capital	$219,091
Tot. Before Ded. for Reserves	$19,984,109
DEDUCTIONS FOR RESERVES	
Wtd. Avg. Depreciation Reserve	(7,408,853)
Taxes Def. - ACRS/MACRS	(1,457,413)
Taxes Def. - Capitalized Interest	35,396
Taxes Def. - CIAC	46,853
Unfunded Pension Reserve	(129,415)
Accum Amort - Capitalized Software	(14,743)
Accum Amort - Deferred Debits	(14,105)
Total Ded. for Reserves	($8,942,281)
Wtd. Avg. Depreciated Rate Base	$11,041,827
Total Depreciated Rate Base: Wtd. Avg.	$11,041,827

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY

Test Year 1995

DETERMINATION OF AVERAGE AMOUNTS OF WORKING CASH CAPITAL SUPPLIED BY INVESTORS

(Thousands of 1995 Dollars)

Description	Adopted
Operational Cash Requirements	
Cash	$0
Special Deposits	192
Working Funds	443
Prepayments	9,256
Other Accounts Receivable	64,014
Total	$73,905
Less: Amounts Not Supplied By Investors	
Accrued Vacation & Empl. Witholdings	58,448
Credit recd for Capitalized Supplies	36,288
User Taxes	19,318
Total	$114,054
Total Operational Cash Requirement	($40,149)
Plus: Average Amount Required	
Average Amount of Working Cash Capital Required as a Result of Paying Expenses in Advance of Collecting Revenues	92,933
Average Net Amount of Working Cash Capital Supplied by Investors	$52,784

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY

Test Year 1995
DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES
(Thousands of 1995 Dollars)

Description	Expense	Avg Lag Days	Product
	(A)	(B)	(C=AxB)
FUEL:			
Fuel Oil	$22,513	15.15	341,072
Gas Purchase	592,494	39.83	23,599,036
Coal	135,025	29.71	4,011,593
Nuclear Fuel-Amt.	59,996	0.00	0
Nuclear Fuel-Other	19,742	80.20	1,583,308
Purchased Power	2,638,834	42.68	112,625,435
Subtotal	$3,468,604	40.98	$142,160,444
OTHER OPERATING EXP:			
Company Labor	608,761	12.00	7,305,131
Goods and Services	505,527	36.78	18,593,266
Materials From Storeroom	47,309	0.00	0
Property Insurance	49,952	0.00	0
Injuries and Damages	28,663	0.00	0
Funded Pensions	38,407	64.11	2,462,256
Benefits & Unfunded Pens	128,125	0.00	0
PBOP	54,554	46.13	2,516,589
Franchise Reqt.	60,584	268.40	16,260,746
Subtotal	$1,521,881	30.97	$47,137,988
Decommissioning	99,822	28.62	2,856,906
Depreciation	730,431	0.00	0
TAXES-OTHER THAN INCOME:			
Ad Valorem Tax - All	146,460	34.66	5,076,799
FICA	49,128	14.72	723,164
Unemp. Tax - Fed.	735	74.67	54,906
Unemp. Tax - Cal.	1,699	80.62	136,940
Empl Training - Cal.	0	80.48	0
Misc. Taxes - Cal.	169	0.00	0
Misc. Local Tax	(650)	0.00	0
Hazardous Waste	2,045	81.25	166,156
Subtotal	$199,586	30.85	$6,157,965
TAXES-INCOME			
Fed. Income Tax	322,481	110.32	35,576,107
Income Tax Deferred	45,966	0.00	0
Investment Tax Credit	0	0.00	0
State Income Tax - Cal.	93,334	76.93	7,180,219
State Income Tax-Ari. & NM	3,683	102.16	376,286
Subtotal	$465,464	92.67	$43,132,613
TOTAL	$6,485,789	37.23	$241,445,915

Exp. Lag Days	37.23	= (C)/(A)
Revenue Lag Days	42.46	
Adj. to Rate Base	92,933	
Rate Base Factor	10,948,894	
New Rate Base	$11,041,827	

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
OTHER OPERATING REVENUE (OOR) FROM CUSTOMER SERVICE CHARGES
ADOPTED TOTAL REVENUE CREDITS
(Thousands of 1995 Dollars)

Account	Item	Settlement	Adopted	Difference
450.100	C&I Late Payment	7,332	7,332	0
450.100	Res Late Payment	6,961	0	(6,961)
451.100	Returned Check	1,194	1,075	(119)
451.200	Reconnection	2,028	1,634	(394)
451.250	Service Estab	17,474	11,669	(5,806)
451.600	Field Assignment	5,820	3,880	(1,940)
	Total	40,809	25,589	(15,220)

Settlement Total Revenue Credits	147,523
Adopted Difference in Customer Service OOR	(15,220)
Adopted Total Revenue Credits	132,303
Change from Settlement Uncollectible OOR	(1,588)
Net Impact of Adopted Customer Service OOR	(13,632)

APPENDIX D
SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
ADOPTED HEALTH CARE BUDGET
(Thousands of 1995 Dollars)

Active Employees	Settlement	Adopted	Reduction
POS	53,991	46,986	7,005
HMO	29,315	23,317	5,998
Dental	12,865	12,805	60
Vision	2,206	2,164	42
Corporate Med	2,230	2,150	80
Subtotal	100,607	87,422	13,185

Retirees	Settlement	Adopted	Reduction
POS	2,564	2,231	333
HMO	1,166	927	239
PrimeCare	36,513	35,107	1,406
Medicare	2,043	2,043	0
Dental	4,085	4,066	19
Vision	840	824	16
Corporate Med	395	381	14
Subtotal	47,606	45,580	2,02
Administration	7,486	7,486	0
Total	155,699	140,487	15,212

Program Totals	1992 Recorded	Settlement	Adopted	Reduction
POS	52,142	56,555	49,217	7,338
HMO	15,733	30,481	24,244	6,237
PrimeCare	27,740	36,513	35,107	1,406
Medicare	1,369	2,043	2,043	0
Dental	13,200	16,950	16,872	78
Vision	2,215	3,046	2,989	57
Corporate Med	3,175	2,625	2,530	95
Administration	6,016	7,486	7,486	0
Total	121,590	155,699	140,487	15,212

Trend Rates (% per year)	Settlement 1993	Settlement 1994	Settlement 1995	Adopted 1993	Adopted 1994	Adopted 1995
Fee-for-Service	11,	11,	11	11,	8,	8
POS	10,	10,	10	10,	4,	1.25
HMO	9,	9,	9	9,	0,	-5.
PrimeCare	14,	13.5,	13	12.4,	11.8,	11.
Dental	10,	8,	8	10,	8,	7.5
Vision	6,	6,	6	6,	6,	4
Corporate Med	10,	10,	10	10,	8,	8

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995

ADOPTED TOTAL COMPENSATION
(Thousands of 1995 Dollars)

	-Total Compensation-	
	Settlement	Adopted
O&M:		
Base Labor Pay		
Steam	93,866	93,308
Nuclear	100,388	99,791
Hydro	11,402	11,334
Other Production	8,137	8,088
Transmission	46,621	46,326
Distribution	111,695	111,031
Customer	90,191	89,655
CS&I	34,139	21,915
A&G	131,105	127,313
Subtotal	627,544	608,761
Pensions & Benefits	170,337	158,496
Capital		
P&B Capitalized	62,199	57,865
Labor Capitalized		
A&G Capitalized	23,396	22,922
Labor Charged Direct	223,077	216,173
Subtotal	246,473	239,096
Total Compensation	1,106,553	1,064,218

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
WAGE FREEZE CALCULATION
(Thousands of 1995 Dollars)

Adopted 1995 Labor Escalation 2.6300%

Mgmt/Admin Pay -- % of Total 49.4800% (Exhibit 760, Appendix D, p. 2)

Adjusted 1995 Labor Escalation 1.3287%

Reduction in 1995 Labor Esc 1.3013%

	Unadjusted Labor $92	Unadjusted Labor $95	Disallowed Labor Esc	Net Labor $95	Disallowed Capital
Steam	85,793	93,866	558	93,308	219
Nuclear	91,754	100,388	597	99,791	234
Hydro	10,421	11,402	68	11,334	27
Other	7,437	8,137	48	8,088	19
Trans	42,595	46,603	277	46,326	109
Distr	102,089	111,696	664	111,031	261
Cust	82,434	90,191	536	89,655	211
CS&I	20,150	22,046	131	21,915	51
A&G	117,059	128,076	762	127,313	298
Total	559,732	612,403	3,642	608,761	1,429

Labor Escalation Disallowed	3,642
Capitalized Portion	1,429

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
DEVELOPMENT OF NET-TO-GROSS MULTIPLIER

Description	Rate (A)	Amount Applied (B)	Total (C=A*B)
Gross Operating Revenues			100.0000
Less: Uncollectible	0.3130%	100.0000	0.3130
Subtotal			99.6870
Less: Franchise Fees	0.8087%	100.0000	0.8087
Subtotal			98.8783
Less: Arizona & New Maxico Income Tax	0.3416%	98.8783	0.3378
Subtotal			98.5405
Less: Superfund Tax	0.12%	98.5405	0.1182
Subtotal			98.4223
Less: S.I.T.	8.6561%	98.8783	8.5590
Subtotal			89.8633
Less: F.I.T.	35.00%	98.4223	34.4478
Net Operating Revenues			55.4155
Uncoll. & F.F. Factor			1.0113
State & Fed. Tax Factor			1.6683
N-T-G Multiplier			1.8045

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
CPUC JURISDICTIONAL FACTORS

Description	Settlement	Adopted
Operating Expenses		
Production	99.436%	99.436%
Transmission	99.756%	99.756%
Distribution	99.900%	99.900%
Customer Accounts	99.983%	99.983%
Cust. Serv. & Inform.	100.000%	100.000%
Administrative & General	99.718%	99.718%
Revenue Credits	99.899%	99.899%
Depreciation	99.660%	99.660%
Nuclear Decommissioning: qualified	99.424%	99.424%
Nuclear Decommissioning: non-qualified	99.689%	99.689%
Taxes Other Than On Income	99.686%	99.686%
Calif & Fed Income Tax Deductions	99.671%	99.67[illegible]
ACRS Deferred & Other Income Taxes	99.661%	99.661%
Rate Base	99.672%	99.672%

APPENDIX D
SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1995
ADOPTED NUCLEAR O&M REFUELING EXPENSE
(Thousands of Dollars)

Description	Cost per Refueling (1992 $)	Cost per Refueling (1995 $)	Wage Freeze Adj	Net 1995 cost per Refueling
SONGS 2&3				
Labor	4,173	4,566	(30)	4,536
Non-Labor	14,015	15,209	0	15,209
Total	18,188	19,775	(30)	19,745
Palo Verde 1,2&3				
Labor	0	0	0	0
Non-Labor	3,905	4,238	0	4,238
Total	3,905	4,238	0	4,238
Grand Total (SONGS/Palo Verde)				23,983

Nuclear Refueling Revenue Requirement Summary

Total System Rev Req	23,983
Plus FF&U	272
Subtotal	24,255
CPUC Jurisdictional Factor	99.436%
Net CPUC Jurisdictional Rev Req	24,118

(END OF APPENDIX D)