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Decision 96-09-092 September 20, 1996

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of Southern California Edison Company to Adopt a Performance Based Ratemaking Mechanism Effective January 1, 1995.	Application 93-12-029 (Filed December 23, 1993)
Commission Order Instituting Investigation into Changing the Method, Timing and Process for Periodically Deriving a Reasonable Revenue Requirement for the Southern California Edison Company.	I.94-04-003 (Filed April 6, 1994)

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SUMMARY

This decision adopts a Performance-Based Ratemaking (PBR) mechanism for Southern California Edison Company (Edison) for recovery of its transmission and distribution (T&D) or nongeneration base rate revenue requirements. This nongeneration PBR will take effect on January 1, 1997. This Decision also adopts rules for a distribution only PBR. We expect that the transition from this nongeneration PBR to a distribution only PBR will occur in 1997 after FERC and this Commission adopt a separation of both the ratebase and base rate revenue requirement between transmission and distribution. We authorize this distribution only PBR to extend through December 31, 2001. Both the nongeneration and distribution only PBRs apply an inflation less productivity update rule to base rates as we did in D.89-10-031, where we adopted our first PBR for local exchange telecommunications utilities. We modify the use of ERAM for base rate revenue requirement. We adopt values for productivity and for service reliability which increase over the term of these PBRs. We also adopt a progressive sharing of net revenue which will allow ratepayers to share in cost savings achieved by Edison. This decision adopts both the nongeneration and distribution only PBRs within the system rate cap adopted in our Electric Restructuring Policy Decision, D.95-12-063 (the Policy Decision).

II. PROCEDURAL BACKGROUND

A. The General Rate Case Decision

An integral element of any PBR mechanism is the starting point - the base revenue requirement - that will be used to determine future rates through application of the PBR formula. It was Edison's position that the base revenue requirement for PBR should be set by our decision on Edison's 1995 GRC, A.93-12-025. Determination of the starting revenue requirement is a necessary precondition to issuance of a decision adopting a PBR mechanism for Edison, because Edison insisted throughout the proceeding that it would withdraw its PBR application and refuse to implement a PBR unless it was first satisfied with the starting revenue requirement adopted by the Commission[1]. Therefore, in order to seriously entertain Edison's PBR proposal it was necessary for us to determine the baseline revenue requirement in Edison's GRC proceeding and ascertain whether or not Edison intended to withdraw its application based on the revenue requirement adopted in the GRC proceeding. We did not decide Edison's general rate case revenue requirement until we issued D.96-01-011 on January 10, 1996.

Ten days after we issued D.96-01-011, Edison filed comments indicating that it was willing to proceed with its nongeneration PBR and accept a GRC revenue requirement authorization as the initial base revenue requirement.[2]

B. Assigned Commissioner's Ruling (ACR) of July 12, 1994

On July 12, 1994, Assigned Commissioner Fessler issued a ruling which bifurcated the hearing of Edison's PBR Application. The Ruling directed Edison to file a "transmission and distribution" or nongeneration PBR to amend A.93-12-029. The Commission encouraged parties to propose a flexible PBR mechanism that could be adopted and conformed to the utility industry over the next six years. The Ruling encouraged parties to address certain factual and policy issues related to electric restructuring, potential modifications to the Electric

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[1] When Edison filed A.93-12-029, it purported to "reserve the right" to review any modifications which the Commission might make to its application "and determine if we are willing or able to accept them. If we are unwilling or unable to accept such changes, then we would withdraw this Application." (A.93-12-029, p. 16.)

[2] As discussed below, while Edison indicated on the one hand that it would accept the GRC revenue requirement as the base revenue requirement for PBR, it concurrently requested an immediate upward adjustment to this base.

Revenue Adjustment Mechanism (ERAM); alternative funding for Demand-Side Management (DSM) and Research Development and Demonstration (RD&D).

C. The Restructuring Decision

In Ordering Paragraph 17 of D.95-12-063, we ordered Edison, PG&E, and SDG&E to file new applications, within 60 days of the decision's effective date, to establish PBR mechanisms, consistent with the guidelines outlined in the Policy Decision. Each application was to include a proposal for a separate distribution and generation PBR. The decision also ordered the parties to file and serve comments in A.93-12-029 on whether Edison's pending performance-based ratemaking PBR proposal should be adopted or not. Various parties filed comments in response to A.93-12-029. Most parties favored adoption of some interim PBR mechanism. In the "Roadmap Decision," D.96-03-032, we extended the filing date for a new application for a distribution PBR.

D. Assigned Commissioner's Ruling of June 21, 1996

In an Assigned Commissioner's Ruling (ACR) issued on June 21, 1996, the date for filing of Edison's distribution PBR application was extended. The ACR recognized that for Edison, the Commission faces at least two options: "adopt a Decision based on the record developed in A.93-12-029 as an interim decision for combined T&D; or request Edison to modify its filing to implement a distribution-only PBR in response to FERC's order which addresses the T&D split."

III. SUMMARY OF PRINCIPAL PBR PROPOSALS

A. Edison

Edison's Nongeneration PBR Mechanism as originally proposed contains the following elements:

> "A revenue indexing formula for application to the level of base rate non-generation revenues adopted in the 1995 General Rate Case ("1995 GRC") and Cost of Capital

> decisions, which incorporates an escalation index for inflation ("the Consumer Price Index or CPI"), incremental revenues for customer growth, and a productivity pledge ("X");
>
> A Cost of Capital Trigger Mechanism to replace the current annual Cost of Capital proceedings;
>
> An overall Net Revenue Sharing Mechanism;
>
> Separate ratemaking treatment for certain categories of costs, identified as "Exclusions" under Edison's proposal;
>
> Provision for "Z-Factor" treatment for major uncontrollable events, both those that can be foreseen but not quantified at this time and those that are currently unforeseeable;
>
> A penalty/reward mechanism to assure continued system reliability, customer satisfaction, and employee safety; and
>
> A penalty/reward mechanism based on Edison's average rate/bill performance relative to a national average of other investor-owned utilities." (Edison Opening Brief, pp. 203.)

Edison believes that its proposal offers significant benefits by replacing traditional regulatory controls with an incentive-based framework for setting the appropriate revenue levels:

> "Under the traditional regulatory approach, the primary incentives for productive efficiency are that (1) shareholders benefit from any cost reductions for a short while until the next rate case incorporates the savings into its forecast

> for upcoming operations and (2) management faces the prospect that the Commission may discover and penalize the utility for improper operations. Under the alternative approach, [incentive-based regulation], the utility is at risk or stands to benefit from all investment and operating decisions, with the risk (or benefit) being loss (or gain) of 100% of the amount at stake if overall earnings levels are below the benchmark rate of return, and 50% if earnings are between the benchmark and cap rates of return." (D.89-10-031, mimeo. p. 211.)

Edison acknowledges that some of the alternative proposals contain elements that might be viewed as preferable to certain aspects of Edison's proposal. However, Edison argues that none of the alternatives, when judged in their entirety as potential alternative proposals, can be viewed as acceptable.

B. DRA

DRA's proposed alternative PBR proposal for this proceeding includes the following elements:

> "1. Reduction of Edison's overall revenue requirement by 5 percent when Phase I of the PBR is adopted. This element is supported by I.94-04-003 which adopted a scope of investigation broad enough to include both base rate and Energy Cost Adjustment Clause components of electric rates, as well as other revenue requirement programs administered by this Commission;
>
> 2. Implementation of price caps for Edison's bifurcated business operations, non-generation and generation, beginning January 1, 1996 following the overall price reduction in 1995;
>
> 3. Adoption of a price rule for customer access services escalating a base revenue requirement by CPI minus an 'X' value adjustment based on an estimate for productivity, a productivity

> 'stretch factor,' a value designed with reference to a competitive regional benchmark using data from the Western Systems Coordinating Council (WSCC) companies and finally a correction value for the upward bias in the CPI;
>
> 4. Continued funding of DSM and RD&D for the initial three-year period at no more than the level recommended by DRA in Edison's 1995 GRC. In addition, adjustments to the customer access service price for DSM effects should be calculated and implemented in an expanded Annual Earnings Adjustment Proceeding (AEAP) where the results of measurement studies for Edison's DSM programs subject to incentives are reviewed;
>
> 5. Complete elimination of ERAM as of the effective date of this Phase I decision for the full scope of Edison's utility business;
>
> 6. A simple sharing mechanism in which Edison takes 100 percent of all gains and losses relative to the price cap;
>
> 7. Z-factor concept with modifications and limitations on Edison's proposed criteria and its list of exclusions from the PBR mechanism;
>
> 8. No rate/bill national comparison since the price cap is designed specifically to achieve this goal;
>
> 9. Increased penalty for diminished Quality of Service, either in system reliability or level of customer satisfaction, without the opportunity for rewards for continued current service levels; and
>
> 10. An approach to Monitoring and Evaluation which includes oversight of Edison's prices, earnings, and operating and expense levels." (DRA's Opening Brief at pp. 42-42, quoting Exhibit 201, II, DRA/McNamara.)

DRA states it has proposed its alternative because Edison's proposal fails to demonstrate that it would produce rate reductions or any other significant benefits to ratepayers. DRA characterizes the difference between Edison's revenue indexing mechanism and DRA's price cap rule as "fundamental,"[3] explaining that DRA's alternative starts with a reduced revenue requirement stream and then applies a price cap to Edison's customer access services. DRA explains that its proposal would provide, among other things, for immediate rate relief to Edison's customers rather than waiting for productivity pledges or a six year experimental program to run its course. DRA believes that this outcome of its proposal also fulfills the spirit and letter of the Commission's criteria and the legislature's guidance in ACR 143 in providing all of Edison's ratepayers with immediate rate relief. DRA submits that its customer satisfaction and reliability mechanisms provide appropriate incentives for protecting ratepayers from degradation of current service levels when Edison implements new cost-cutting strategies under PBR.

Alternatively, DRA submits that if the Commission approves certain elements of Edison's proposal, it should only adopt them with conditions. At the very least, DRA proposes that the Commission adjust the starting point downward and adopt DRA's alternative recommendations regarding revenue sharing and capital structure treatment. Additionally, DRA urges the Commission to reject Edison's customer growth allowance as proposed. DRA opposes other specific elements of Edison's proposal. DRA also states that regardless of which PBR mechanism the Commission adopts, the Commission should adopt DRA's recommendations on customer satisfaction and reliability mechanisms, monitoring and evaluation and auditing compliance.

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[3] DRA's Opening Brief at p. 2.

C. <u>Industrial Users</u>[4]

The Industrial Users believe their PBR proposal for this proceeding is easy to understand and implement, and begins the process of reducing Edison's rates. Industrial Users advocate that their proposal meets all three of the Commission's goals: ease of implementation, lower electric rates for customers and increased financial opportunities for Edison. Industrial Users' proposal, set forth in detail in Exhibit 320, can be summarized as a rate cap that requires Edison to reduce its average weighted typical bill to 125% of the national average by the year 2000. Within this framework, Edison is free to pursue any opportunity for earnings growth with the maximum amount of decision-making freedom.

Industrial Users believe that their PBR mechanism provides significant electric rate decreases (in nominal terms) in every year of the PBR time frame. In return, Industrial Users would allow Edison to keep all returns on investment, which they estimate to be a potential annual benefit to Edison of about $142 million. Industrial Users also state that their proposal reduces the potential for errors in the implementation of PBR, such as those which might result by the adoption of an incorrect productivity factor. They also state that their proposal eliminates gaming of PBR revenues which might result, for example, by deferring revenues until the next year to avoid sharing, allowing electric rates to increase because the higher revenues outweigh the penalties, and avoiding problems with accounting for imprudent costs.

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[4] Industrial Users intervenor group is comprised of Air Liquide America Corporation; Air Products and Chemicals, Inc.; Anheuser-Busch Companies; BOC Gases; The Chevron Companies; Hughes Aircraft Company; Kimberly-Clark Corporation; Nabisco, Inc.; Praxair, Inc.; and Steelcase, Inc.

D. <u>Joint Parties</u>[5]

The Joint Parties' proposal can be summarized as follows:

"1. Consistent with ACR 143, the Commission should articulate that its fundamental goals in adopting PBR mechanisms are:

a. to establish incentives that enhance the competitiveness of utilities to ensure that lowest cost services are provided to all customers; and

b. to provide immediate financial benefits to utility customers.

2. The Commission should state clearly that its objectives in adopting PBR mechanisms are not merely to decrease the Commission's regulatory activities, lessen utility regulatory 'burdens,' or improve shareholder earnings.

3. The Commission should ensure that any PBR mechanism it adopts will comply with ACR 143.

4. The Commission should adopt the following features of PBR, as testified to by Mr. Marcus:

a. Use a revenue per customer approach, and not a price cap;

b. Adopt an 'X factor' of 4 percent, not [Edison's] proposed 1.4 percent;

c. Reject [Edison's] proposal for a special allowance for new customer costs;

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[5] The Joint Parties consist of the California Department of General Services, TURN, Center for Energy Efficiency and Renewable Technologies, Natural Resources Defense Council, and Environmental Defense Fund. TURN endorses the positions set forth by the Joint Parties as the sponsors' preferred "CPI-X"-based PBR proposal. However, TURN's preferred approach to PBR is its own proposal summarized in part E below.

d. Adopt a shared savings approach that ensures significant benefits to ratepayers;

e. Revise [Edison's] proposals for the non-price performance indicators for reliability and customer satisfaction, using DRA's proposal as an interim strategy and removing [Edison's] proposed national rate and bill indices;

f. Limit the number of exceptions to the PBR mechanism (the so-called 'Z factors'); and

g. Ensure adequate PBR implementation, monitoring and governance, especially in light of ACR 143.[5] (Joint Parties' Opening Brief at pp. 2-3.)

The Joint Parties state that their proposal is the only "CPI - X"-based proposal presented in this case that is consistent with ACR 143. The Joint Parties state that their proposal provides meaningful incentives to enhance Edison's competitiveness in providing least cost services to all of its customers. The proposal also offers immediate sharing with customers of cost savings. For example, the Joint Parties do not believe that Edison's proposal provides for meaningful sharing of productivity improvement with ratepayers, and believe that a significant rate reduction is required. The Joint Parties also believe that the adopted PBR mechanism should be carefully designed so as not to lose sight of energy conservation, reliability, customer service, and the environment while pursuing the goal of rate reduction. They believe that their proposal meets the above tests.

E. TURN

TURN recommends reinvigorating the GRC proceeding and conducting a GRC every two years.[6] Under TURN's proposal, the GRC would be the primary, if not exclusive,

[6] As stated above, the proposal set forth here is TURN's primary proposal. TURN's alternative proposal is that advocated by the Joint Parties as described in section D above.

forum for determining rates and ratemaking policy for Edison. The separate annual cost of capital proceeding would be eliminated for Edison and that issue would be addressed in the GRC. TURN's proposal would eliminate other rate adjustment mechanisms and formulas which exist in addition to the GRC.[7] Edison would have to justify any rate adjustment procedure or formula aside from the GRC anew based on today's circumstances. TURN states that including a specific sunset date in any approval of a non-GRC procedure or formula will prevent the current problem of mechanisms which have outlived their usefulness continuing in effect and, more often than not, creating no-longer-justified but near-automatic revenue and rate increases. TURN also states that elimination of balancing accounts will largely eliminate the need for reasonableness reviews.

TURN advocates a two year GRC cycle (the norm prior to the mid-1980s), since attrition adjustments would be eliminated. According to TURN:

> "This approach would provide Edison with a fixed operating 'budget' for a two-year period. Any savings and efficiencies that the utility is able to achieve relative to that budget would flow 100% to shareholders during that two-year period. Thereafter the savings would presumably be captured in future rate cases for the benefit of customers, although in practice efficiencies achieved during the year the GRC is being litigated often would not be reflected in reduced rates until the next GRC, thus allowing the shareholders to reap all of the benefits for as much as three full years. ... [E]ven after the savings are captured in a subsequent GRC, shareholders continue to benefit because the utility becomes, by lowering its rates, more competitive with competing service territories as well as other products and services.

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[7] TURN suggests the procedures to be eliminated include the Attrition Rate Adjustment, the separate annual cost of capital proceeding, ERAM, rate design windows, separate applications such as those for low-emission vehicle funding, and balancing accounts in general.

competing for customer dollars." (TURN Opening Brief at pp. 14-15.)

TURN asserts that its proposal is superior to any other parties' proposals in order to achieve the goal of rate reduction. By definition, the "CPI - X" mechanism to achieve rate reduction is largely dependent upon the level at which the Commission defines "X." Under other parties' proposals, that decision is made once and then left in place for six years. However, TURN advocates that its proposed two year rate case cycle is more flexible because it would not exclusively rely on any single Commission determination, and would also provide sufficient opportunities for the Commission to correct any error in those determinations to prevent undue harm either to the utility or its customers. TURN also states that its proposal is the most successful among the parties' in maintaining a reasonable opportunity for Edison to earn a fair rate of return and providing Edison's management with a predictable framework to achieve that end. TURN states its proposal does not rely on regulators telling the utility how to run its business, but rather sets up an operating budget, as well as a reasonable authorized rate of return, for the company, and allows management to manage within that parameter. TURN states that the two year GRC cycle would provide adequate incentive to Edison's management to continue pursuing all reasonable cost reductions since the achieved savings would be retained by the utility for up to three years before being captured in the subsequent GRC and flowed through to Edison's customers.

TURN also discusses the procedural benefits of consolidating a large number of ratemaking proceedings into a single forum. First, it would achieve the simplified and streamlined regulatory process sought by the Commission, Edison, and the Legislature. Second, it would serve to improve regulation itself at a reduced cost, since the Commission would be better able to view the utility as a whole and to assess how it compares with other utilities. Third, the proposal would provide intervenors with a more meaningful opportunity to be involved in the regulatory process by permitting them to concentrate on a single proceeding rather than multiple proceedings. Fourth, the proposal would provide for a regular and more frequent forum to address service quality issues rather than having to wait once every six years. Fifth, the proposal would better serve ACR 143's objectives of protecting public health, complying with environmental laws and regulations, and ensuring the existence and operations of programs to assist low-income ratepayers, since under any "CPI-X" proposal, the utility would have the incentive to minimize the costs involved in achieving these goals, and the increased lag between comprehensive reviews will reduce the Commission's ability to ensure that the objectives are being met. Last, TURN states that its proposal provides greater protection against price discrimination.

IV. THE ROLE FOR PBR REGULATION

We have accepted the benefits of incentive based or PBR regulation for several years. We first replaced our traditional rate case regulation with a PBR, which we called the New Regulatory Framework (NRF), for the local exchange telecommunication utilities, in D.89-10-031. In adopting PBRs, we recognize that traditional rate case regulation includes a direct link from costs to rates and does not include an independent and explicit incentive to increase efficiency through lowering costs. To encourage efficiency, effective PBR regulation breaks this feedback link from costs to rates and includes an incentive for the utility to reduce costs. Moreover, effective PBR regulation must include appropriate standards for service and safety.

In D.89-10-031, we adopted a form of PBR regulation, first used in the United Kingdom, and often called "CPI - X" regulation. This form of PBR regulation adopts starting rates based on an analysis of utility costs with these rates then updated in each subsequent year by a rule which includes expected changes in input prices, CPI, and productivity, X.

discussion below, we refer to this price less productivity adjustment, or CPI - X, as the update rule.

To make this update of utility rates independent of the utility's costs, the price and productivity values should come from national or industry measures and not from the utility itself. The independence of the update rule from the utility's own costs allows PBR regulation to resemble the unregulated market where the firm faces market prices which develop independently of its own cost and productivity. In contrast, traditional regulation often updates rates through a review of the utility's own costs and productivity. The form of this PBR update rule of 'price less productivity' or CPI-X arises from the unregulated market where, independent of demand response, a firm's output price will change to reflect changes in its input prices less its change in productivity, where productivity is simply the change in the firm's outputs less its change in inputs, both value weighted.

Finding a measure for the price term in the update rule requires a choice between a general price index such as the well-known CPI or an industry specific index. The former choice involves less controversy but uses a general approximation to industry specific prices, and this approximation can work reasonably well during periods of generally low inflation. While the latter choice clearly tracks industry costs more closely, it does engender more controversy because often it requires construction of a new industry specific price index to track industry price changes closely. Complexity readily arises in the construction of price indices; for example, an accurate current price index for labor requires a weighted average wage for Edison's many different classifications of workers from clerks to system engineers.

The productivity measure should come from a forecast of industry-specific productivity. However, such studies are not common and most published econometric studies not only assume efficient operation but also use historical data. In D.89-10-031, we relied on a study of AT&T's historical productivity and expert judgment in setting the productivity value for the local exchange utilities. Realizing that technological change in telecommunications offered the opportunity for substantial productivity and wanting to encourage increased efficiency in utility operations, we added a 'stretch' factor to set the productivity value or X.

We note that improved efficiency can arise from three sources: adopting more efficient technology in meeting current demand, realizing economies of scale when expanding the operation, or reducing existing inefficiencies in the current operation. In the nongeneration business and particularly in the distribution business, the first source of productivity may contribute only selectively toward greater efficiency and lower rates. The incentives of this PBR should discover the opportunities to increase the efficiency of the current operation and thereby lower rates.

In D.89-10-031, we also adopted a net revenue sharing rule which allows the utility to keep some of the increased net revenue which occurs if the utility can reduce its costs. Adoption of this rule should increase the utility's incentive to reduce costs. Allowing the utility to retain some of the net revenue from cost reduction efforts also resembles the competitive market where a firm can increase its profits by lowering its costs. Combined with the use of independent prices, the use of a net revenue sharing rule emulates the outcome of a competitive market.

Thus, we see PBR as emulating the competitive process to encourage utility management to make decisions which resemble an efficient or competitive outcome. An efficient utility will control rates which benefits ratepayers. However, we want to ensure fairness to ratepayers, employees and shareholders in the PBR process. This requires balancing potentially conflicting interests. The utility can increase short run profits through reducing variable costs, but without revenue sharing such cost reductions will not lower rates. Moreover, such reductions not only can affect staff immediately but the service quality impact may only appear much later.

In this PBR for Edison, we balance these interests by requiring a progressive sharing of net revenue between shareholders and ratepayers and by having both the productivity and service quality measures increase over the duration of the PBR. By progressive sharing, we mean in this order that the utility share of net revenue increases as its earned return becomes greater or smaller than the benchmark return; correspondingly, the ratepayer share decreases. By having these productivity and service quality measures increase, we intend to allow both Edison management and its employees time to adjust to PBR regulation and to find opportunities for cost reductions, which will lower ratepayer bills, increase Edison's profits and minimize the impact on employees. Allowing time to discover such opportunities for cost reductions could defer some of the rate reductions for ratepayers, but we believe that when such reductions occur, they will represent more permanent efficiency gains.

In approving this PBR, we intend to adopt a framework which will apply downward pressure to rates. The parties noted that Edison's own forecasts showed that its PBR proposal would likely not lower rates substantially when compared to traditional rate-making. However, we note that the parties could only compare forecasts. Such forecasts include uncertainty and can only lead to speculation about the effect of alternative regulation on rates. Rather than rely on speculation and forecasts we order a progressive net revenue sharing incentive in this PBR which encourages Edison to lower costs and allows ratepayers to share in these reduced costs through lower rates. This progressive sharing incentive gives ratepayers a larger share of Edison's easier cost reductions and the shareholders a larger share of the more difficult reductions. We see this progressive net revenue sharing incentive as the key to lower rates within a structure which balances the interests of ratepayers, employees and shareholders.

V. THE NONGENERATION PBR

In this Section, we describe our PBR for Edison's nongeneration business. This PBR will become effective on January 1, 1997. We expect that during 1997 FERC and this Commission will approve the separation of Edison's nongeneration business into transmission and distribution operations. Our Decision today also adopts the adaption of this nongeneration PBR to a distribution only PBR, which will extend through December 31, 2001.

The transition from current regulation to PBR regulation requires changes to existing policies as well as the introduction of new policies. First, we separate Edison's base revenue requirement between generation and nongeneration. Second, we order Edison to file tariffs which set separate rates for generation and nongeneration base revenue requirement effective January 1, 1997; and we will order Edison to file changes to these tariffs as part of our unbundling proceeding within 60 days after FERC and this Commission have completed the separation of Edison's nongeneration business into transmission and distribution and we will order that Edison file these tariff changes with an effective date coordinated with the beginning of FERC set transmission rates. Third, we adopt an update rule which, using the CPI - X rule, adjusts these base rates annually for the effects of inflation and productivity. Fourth, we describe our policy for exclusion of certain accounts from the scope of the PBR, and our policy for modification of the effect of sales balancing achieved through the ERAM balancing account for base rate revenue requirements, and our policy for Z-factors, which allow cost recovery for extraordinary events. Fifth, we present our proposal for cost of capital and capital structure and the related net revenue sharing plan for shareholders and ratepayers. Sixth, we describe our service quality, customer satisfaction and safety incentives. Finally, we review our implementation and monitoring plan.

A. Nongeneration Base Revenue Requirement

In D.96-01-011, we adopted an authorized level of base revenue requirement (ALBRR) for Edison's 1995 Test Year General Rate Case. We authorized $4,017 million for this total base revenue requirement, and we also adopted a total ratebase of $11,042 million. We determine Edison's nongeneration base revenue requirement by adopting rules which separate this total base revenue requirement and total ratebase into generation and nongeneration components.

We recognize that Edison stated that it separated its ratebase into generation and nongeneration using FERC and NARUC guidelines. We accept Edison's use of such guidelines, but we order Edison in its compliance Advice Letter to describe the method and result of its assignment of ratebase assets such as lines, transformers and switches at the generation transmission interconnection for each Edison generating plant. This assignment should recognize our recommendation in our recent comments to FERC regarding separation of transmission and distribution facilities.

To separate Edison's authorized level of base rate revenue requirement (ALBRR) into generation and nongeneration requires an account specific allocation of operation and maintenance (O&M) costs. The accounts include the following: production, transmission, distribution, customer accounts, customer service and information, and administrative and general. Edison has assigned its accounts labelled transmission and distribution O&M to nongeneration. We accept this assignment.

Edison has assigned both customer accounts and customer service and information to nongeneration. We accept Edison's assignment of customer accounts to nongeneration because most of these costs such as opening and closing accounts, changing service or tariff, billing and responding to customer billing problems vary with customer requirements. This allocation recognizes that most of customer account costs are associated with metering, which almost always occurs at a distribution level voltage. As such, these costs properly belong in the distribution function within nongeneration. Therefore, we also expect that in the separation of nongeneration most of these costs will appear in the distribution business. We cannot accept DRA's recommendation of a labor-only allocation method because customer costs vary with Edison's customers not Edison's employees.

We do not accept Edison's assignment of customer service and information (CS&I) costs to nongeneration. These costs come from DSM and economic development. We will assign DSM costs to generation because generation represents the primary source of avoided cost in DSM. We recognize that development of a new funding source for DSM could require re-allocation of these costs. Because of the extensive customer contact required for economic development, we will assign these costs to nongeneration. We cannot accept DRA's plant based allocation of these expenses because we do not fund either program based on the value of current plant in service.

We accept Edison's and DRA's labor-based allocation of administrative and general costs because these provide general support for Edison's other employees. We accept DRA's allocation of RD&D which is based on Edison's 1995 GRC filing and which allocated 47 percent to nongeneration and 53 percent to generation. We accept Edison's allocation of franchise fees to nongeneration because this allocation follows FERC and Commission Decisions. We accept DRA's allocation of uncollectibles based on total other expenses because an uncollectible bill includes both generation and nongeneration expense. We order property taxes and other taxes allocated based on net plant.

Finally, DRA recommends a downward adjustment of Edison's overall revenue requirement, not just customer access services, by a full 5 percent. (DRA Opening Brief, p. 45.) Edison opposes DRA's proposed reduction. "The Commission should not be asked to conclude that a certain level of costs are reasonable (by virtue of the GRC Settlement) and then immediately turn around to extract an additional $390 million out of authorized 1995 revenues. If spending a certain amount of dollars to cover operating costs is reasonable under traditional ratemaking, then spending the same costs under PBR to provide the same level of service must be viewed as per se reasonable; conversely, the extraction of additional revenues by DRA (and others) must be condemned as unreasonable." (Edison Reply Brief, p. 78) We agree with Edison's reasoning. We find that DRA has offered no compelling reason for us to impose a reduction of 5% to the revenue requirement we found to be reasonable in D.96-01-011.

We order Edison to present in its compliance Advice Letter a separation of total base revenue requirements into generation and nongeneration, which uses the accounts from Table A-5 and the separation presentation in Table B-1 from volume SCE-2 of its Application.

B. Rates for Nongeneration and Distribution Base Revenue Requirement

B.1 A Comparison of Rate and Revenue PBRs

In D.89-10-032, we approved a PBR for local exchange utilities. In that PBR we adopted rates for the initial year of the PBR and also adopted a formula which allows changes to these rates in subsequent years based on changes in inflation and productivity. In this order we refer to this formula as the update rule because it updates prior rates or revenue for the effects of inflation and productivity.

In D.89-10-039, we adopted an update rule of inflation less productivity which is similar to CPI-X and we ordered that each utility apply this update rule to current rates to determine future rates. On the other hand, Edison has requested a PBR which adds a customer growth allowance to its prior year base rate revenue requirement, then applies the update rule of CPI-X to both the customer growth and base rate revenue requirement, and then converts this into next year's rates using forecasts of customers and sales. Edison has also proposed to continue the ERAM balancing account which eliminates the risk in these forecasts. To simplify our discussion and only for purposes of nomenclature, we will call the type of PBR approved in D.89-10-032 a rate PBR and we call the type of PBR which Edison requests a revenue PBR.

A rate PBR uses rates for the initial year of the PBR and then changes rates in a subsequent year by applying the update rule for the effects of inflation less productivity directly to rates in the prior year. In contrast, a revenue PBR adds a customer growth allowance to the revenue requirement for the prior year, applies the update rule for inflation less productivity to this combined revenue requirement and then converts this updated revenue requirement to rates based on a forecast of sales and customers.

Thus, use of a revenue PBR requires a forecast of sales and customers, which creates a source for considerable controversy because for a given revenue requirement a low sales forecast will raise rates which increases utility revenues while a high sales forecast will lower rates. However, we want adoption of PBRs to reduce this sort of regulatory controversy. This controversy does disappear with use of an ERAM balancing account. However, we intend to reduce our reliance on balancing accounts because their use does not emulate the competitive market.

On the other hand, use of a rate PBR does not require a sales forecast because a rate PBR simply updates current rates with CPI-X to determine future rates, which eliminates the controversy of sales forecasts or balancing accounts such as ERAM. Compared to a revenue PBR, a rate PBR does assume that incremental revenues from the growth of sales at least covers the incremental cost of serving new customers. We can design a rate PBR to produce the same expected revenue as a revenue PBR, given forecasts of customers, sales and incremental costs. However, because actual and expected sales will differ, rate and revenue PBRs will yield different actual revenue.

In their testimony, both DRA and Edison developed simple models to compare rate and revenue PBRs. To use these models requires forecasts of average and incremental customer costs as well as sales and customer growth rates. In its Application, Edison states that its incremental customer cost is $779 while its average customer cost is $514. Moreover, in its Application, Edison states that it expects sales to grow at 2.87 percent annually while customers will grow at 1.86 percent annually which implies a growth of sales per customer of about 1 percent although in recent ECACs Edison has shown lower actual sales and customer growth rates. Using these data from Edison's Application in the simple models developed by DRA and Edison indicates that a rate PBR will generate as much revenue as a revenue PBR even if the incremental cost of serving a customer exceeds average cost by as much as 50 percent as long as the sales per customer grows by at least half the rate of the customer growth rate, which is consistent with Edison's recent experience.

We have described how a revenue PBR will require substantially more regulatory intervention than a rate PBR. A revenue PBR will require either a controversial sales forecast or a sales balancing account. A rate PBR will require neither. Moreover, we have described how Edison will likely cover its revenue requirements under a rate PBR. We adopt a rate PBR, rather than a revenue PBR, to meet our policy objectives of allowing Edison to meets its revenue requirements under reasonable assumptions and of minimizing regulatory intervention in a PBR.

B.2 Adjustments to Nongeneration Revenue Requirement

In its PBR Application, Edison requested a base rate revenue requirement for nongeneration based on its request in its rate case Application (A.93-12-025). In D.96-01-011, we adopted an authorized level of base rate revenue requirement (ALBRR) of $4,017 million, which is less than Edison's request in its rate case Application and we removed the base rate revenue requirement associated with SONGS 2&3, including ALBRR for general and administrative costs in D.96-04-059.

In its compliance Advice Letter, we order Edison to separate its generation and nongeneration ALBRR after making all adjustments which we have ordered since Edison filed its PBR Application. These adjustments should be consistent with the showing in Edison's current ECAC Application, including any updates. In workpapers accompanying its compliance Advice Letter, Edison will independently show the impact of Edison's recommendation in any outstanding Application on this ALBRR separation of generation and nongeneration.

B.3 Rates for Generation and Nongeneration Base Revenue Requirement

To adopt a rate PBR for nongeneration requires determining separate rates for nongeneration and generation base rate revenue requirement. To accomplish this requires separating all existing rates and charges which recover base revenue requirement into rates and charges that separately recover generation and nongeneration base revenue requirement. These separate rates will form the rates to which we will then apply the update rule. Edison shall develop these rates and charges using the methodology which we adopted in our Phase II decision in Edison's last GRC, and shall provide complete workpapers showing the details of all calculations and the source of all data. In the construction of these rates, Edison will use, where necessary, the sales forecast, which we adopted in the last Edison ECAC, which is consistent with the policy adopted in our decision on flexible pricing in Phase 2 of Edison's GRC, D.96-08-025.

We order Edison to submit these rates and charges in its tariffs in its compliance Advice Letter filing, but we do not order Edison to bill customers for these separate rates until we separate nongeneration base rate revenue requirement into transmission and distribution which will occur after 1996.

B.4 Nongeneration Revenue Requirement as of January, 1997

In D.96-01-011, we required Edison to file an Application if it requested an adjustment for inflation, and we discussed the transition from rate case regulation to PBR. In our adoption of this PBR, we will allow Edison's to apply its update rule of CPI-X to obtain rates effective January 1, 1997 for nongeneration rates effective in 1997. In its PBR

Application, Edison requested a revenue PBR which included both this update rule and a customer growth adjustment. We are not adopting a revenue PBR and although Edison has experienced customer growth, we will not allow Edison to add a customer growth allowance to its base revenue requirement.

B.5 Rates for Distribution Base Revenue Requirement

To move from a nongeneration PBR to a distribution PBR requires the separation of nongeneration ratebase and revenue requirement into transmission and distribution which will occur both at FERC and here. In Order 888, FERC established seven criteria for the functional separation of transmission and distribution components. In its FERC filing made on April 29, 1996, Edison requested that FERC declare transmission facilities as those carrying voltages 230kV. We expect that FERC will respond to this request with a declaratory order later this year. After that, we expect that each utility will file a transmission rate case with FERC for approval of its open access transmission tariffs and that each utility will have filed a distribution PBR here at this Commission or modify broader PBRs in place. Consequently, this Commission will consider each distribution PBR while FERC considers the companion transmission rate case. For Edison, we decide most issues for its distribution PBR in our decision today.

FERC approval of these tariffs should occur well before January 1, 1998, to meet the planned start date of the ISO. Moreover, FERC's approval of the supporting ratebase and revenue requirement should also occur well before January 1, 1998, which will allow Edison, PG&E and SDG&E to complete their distribution PBR filings here. FERC's approval of the ratebase and revenue requirement for transmission will help us make a final determination of the initial value of the distribution ratebase and revenue requirement for each utility. Absent coordination between FERC and this Commission, this separation of the nongeneration revenue requirement could produce duplication or omissions. With coordination, we expect that this separation will occur well before January 1, 1998, in order to allow for implementation on that date.

Edison apparently proposes both an initial and continual coordination between transmission and distribution revenue requirement. In its recent July 15, 1996, Application for Unbundling and Generation PBRs, Edison proposes to treat transmission as a revenue credit against the nongeneration revenue requirement established in this decision. This revenue credit concept implies that Edison expects that we will adopt as Edison's initial distribution revenue requirement the residual between nongeneration revenue requirement and the transmission revenue requirement adopted by FERC. Moreover, this revenue credit concept also implies that Edison expects that we will adopt a balancing account which will continue to buffer fluctuations in transmission revenue with compensating changes in distribution rates.

Such compensatory rate-setting blurs the jurisdictional line between FERC and this Commission although it could help simplify any subsequent re-classification of distribution or transmission. Edison's revenue credit concept is consistent with Edison's Application for its nongeneration PBR, which requests a PBR based on revenue requirement, rather than rates, and requests a continuation of ERAM. In our decision today, we order a rate PBR, not a revenue PBR, and we order elimination of ERAM balancing account treatment for base revenue requirement. Because Edison has not yet filed its request with us for a revenue credit, we cannot act on this proposal.

C. The Update Rule: Inflation, Productivity and Customer Growth

In this Section, we adopt our update rule, price less productivity, for a rate PBR. Because it requests a revenue PBR, Edison requests a rule which includes an adjustment for prices, productivity and customer growth. We accept Edison's request to use the CPI as the proxy for the inflation change but we adopt a different rule for productivity. We order an annual use of this update rule following Edison's proposed implementation schedule. Moreover, because we adopt a rate PBR, we review but do not adopt the customer growth allowance.

C.1 The Inflation Measure

With respect to inflation, Edison proposes the use of the CPI not because the CPI directly represents the cost of its inputs but because over the past decade the CPI has tracked the Wholesale Price Index. We note that the WPI includes prices of inputs used by all industries, not just the electric utility industry. To establish an accurate inflation or price index for the nongeneration business of the electric utility industry requires completing a study which groups substitutable inputs (e.g., poles) and then finding a inflation index which represents each group of inputs. No party in this proceeding presented such an industry-specific price index. A complex issue concerns an accurate inflation index for the opportunity cost of capital which includes its price change as well as the return of and return on capital, particularly one which reflects any difference between ratebase and economic depreciation rates as well as time varying renewal rates for the capital stock.

As part of the mid-term review, we order Edison to complete a study which defines an industry-specific price index, which at least proposes an index with three aggregate inputs: capital, labor and materials. As part of this index, Edison will present its proposal for an current opportunity cost of capital. As part of this study, Edison will show the difference in application of a price index to all capital related costs, to its proposed opportunity cost of capital, and only to those capital costs not subject to long term commitment at the beginning of this PBR (e.g., depreciation and bonds whose nominal commitment extends beyond 2001 as of the start of the PBR).

Use of the Consumer Price Index (CPI) from the United States' Department of Labor Bureau of Labor Statistics' (BLS) provides a general and usually much less controversial choice as proxy for a utility's input prices. (In its testimony, DRA noted that the CPI contains an upward bias of 0.25 to 0.50 percent due to the BLS' measurement problems.) In D.89-10-031, we adopted a similar index, the Gross Domestic Price Deflator Index (GDP-DI), not the CPI, as a proxy for the utility's input prices. Because both the GDP-PI and the CPI measure aggregate output prices, their use as input price proxies implies inclusion of an adjustment for expected aggregate productivity as noted by both DRA and Edison in their Workpapers. However, no party presented testimony which indicated the size of this adjustment.

We adopt the CPI as the inflation or price index for both the nongeneration and distribution PBRs.

C.2 The Productivity Measure

Edison's study of total factor productivity for its entire (generation and nongeneration) system presented in its 1995 Test Year General Rate Case, verified by DRA through its own independent analysis, reported a value of 1.4 percent for the system. Edison's study of total factor productivity for its nongeneration business, presented in Edison's revised PBR Application in August, 1994, reported a value of 0.9 percent for nongeneration. In its recommendation for a value for X, Edison then included a 'stretch' factor to raise the value for system productivity from 1.4 to 1.8 and the nongeneration value from 0.9 to 1.4 percent.

In its evaluation of Edison's revised PBR Application, DRA accepted the results of Edison's total factor productivity studies although DRA noted that such studies reflect both statistical and model error, where model error includes the assumption that Edison has been operating efficiently. As indicated above, we would prefer to use an industry study to set the productivity value but both Edison and DRA relied on a utility specific study because neither could identify an industry study.

Several parties recommend values for X which meet their policy objective of lowering Edison's rates toward the national average. JBS points out that Edison's productivity rose to 2% from 1982 to 1995 and that from 1985 to 1992, total T&D capital expenditures decreased. Edison concedes that more recent measures of Edison's historical productivity are higher, but Edison counters that this trend is not expected to continue into the future. Joint Parties' examination of Edison's O&M expenses for transmission, distribution and customer accounts for the period from 1987 to 1992, showed cost reductions of 2.9%, which yielded 3% in cost reductions when adding A&G expenses, but we note that these expenses represent much less than half the nongeneration revenue requirements. Thus, these parties present only partial, not total, factor productivity analyses, for recent but short time intervals, with such short time intervals not necessarily supporting sustainable forecasts. Consequently, we face uncertainty about potential productivity. However, we do not necessarily require a precise forecast of productivity because our progressive net revenue sharing policy, discussed below, will allow ratepayers to keep much of the more achievable productivity gain.

We recognize the relationship between productivity and system rates in developing our policy for a value for the productivity or X factor, but we will adopt a value for X which primarily reflects our assessment of achievable productivity.

In the absence of an industry study, we must rely substantially on the firm-specific study of Edison. However, we believe that Edison will discover opportunities for cost reductions as they work with employees over the course of this PBR. Therefore, we adopt a productivity measure which starts with a value of 1.2 and increases by 0.2 percent a year for the next two years. Thus, we order productivity or X values of 1.2 for 1997, 1.4 for 1998, and 1.6 for 1999 through 2001. These values will apply to both the nongeneration PBR and its successor, the distribution PBR. Over the five year period, the productivity averages 1.48 percent which is above Edison's proposed value based on a historical value of 0.9 percent and a 'stretch' factor of 0.5 percent.

If Edison can achieve higher productivity, then our net revenue sharing mechanism will allow ratepayers to share much of the associated cost reduction; for example, if Edison can achieve 3 percent productivity, then ratepayers will receive two-thirds of this. (We discuss the details of this example in the section on net revenue sharing.) Thus, net revenue sharing gives Edison an incentive to achieve higher productivity and gives ratepayers a substantial share of the cost reductions.

C.3 The Customer Growth Measure

In D.89-10-031, we adopted a rate PBR, one which applies the update rule for price less productivity to last year's rates to derive next year's rates. To simplify the use of this update rule, we actually apply the update rule as a surcharge on the customer's bill.

However, Edison has applied for a revenue PBR, not a rate PBR. Edison applied for a revenue PBR because Edison asked to retain the ERAM balancing account, which means that rates would reflect the PBR update rule and any ERAM adjustment. A revenue PBR applies the update rule to last year's base rate revenue requirements, adds an adjustment for the cost of customer growth and then translates this revenue requirement to next year's rates using a forecast of next year's sales, demand and customers. Without adding the new customer allowance to the revenue requirement, rates decline in subsequent years when the static revenue requirement is divided by the increased sales associated with customer growth.

To develop the total cost of customer growth only requires values for the incremental cost per customer and the expected number of new customers served in the following year. As an estimate of the expected number of new customers, we will use the most current historical value for customer growth, not a forecast value, because customer growth tends to change slowly and because using this historical value will create less controversy than using a forecast. Edison stated that it used a methodology presented in its earlier GRCs to develop its forecast of incremental nongeneration cost of $779 for serving each new customer.

DRA noted in its Testimony that Edison's average cost is $514 per customer, but average cost includes historical depreciation which lags incremental cost when input prices rise. No other party presented evidence on nongeneration incremental cost.

We accept Edison's incremental cost of $779 for its customer growth allowance. However, because we are adopting a rate PBR, we will not include a customer allowance.

D. PBR Adjustments to the Nongeneration Base Rate Revenue Requirement

In this Section, we describe our policies for adjusting the nongeneration base rate revenue requirement which we adopted in Section B above. Such adjustment factors include Z-factors for unexpected events, modification of ERAM for the balancing account collection of authorized base rate revenue requirement (ALBRR), and other specific account exclusions. We address each in turn below.

D.1 Z-Factors

We recognize that a utility's operating environment and its costs change continuously, often due to unexpected events. In D.89-10-031, we recognized that unexpected events, which we labelled Z-factors, could lead to changes in the utilities' costs, some of which we would want included in the utilities' revenue requirements and some of which we would not. We recognize that unregulated firms in all industries face unexpected events. In response to some events, the market clearing price will compensate for the cost of these events while in response to other events the market price will not, which means the firms must absorb the impact. In NRF, we developed criteria to assess the nature of the event for its inclusion in the utility's revenue requirements and we selected inclusion criteria to simulate the unregulated market.

We adopted nine criteria which we will briefly summarize below only for reference; but this summary does not replace the criteria as developed and described in

D.94-06-011. First, the event causing the cost must be exogenous to the utility. Second, the event must occur after implementation of the PBR. Third, the utility cannot control the costs. Fourth, the costs are not a normal part of doing business. Fifth, a event affects the utility disproportionately. Sixth, the PBR update rule must not implicitly include the cost. Seventh, the cost must have a major impact on the utility. Eighth, the cost impact must be measurable. Ninth, the utility must incur the cost reasonably. As an example of the application of these criteria, an increase in the price of poles or transformers after implementation of the PBR could meet the six criteria of being exogenous, external (not controllable), unique (to the industry), measurable, reasonably incurred after PBR implementation but would not necessarily meet the three criteria of having a major impact, not being a normal cost of business, or not being part of the PBR update rule (which includes a general inflation adjustment).

Edison proposed a simplified set of four criteria. Edison apparently objects primarily to the criterion which requires that the event affect the utility disproportionately and cites the example of a Federal tax law change which affects all firms. Cost recovery regulation often allows a utility to raise its rates to recover such a cost. However, the Z-factor criterion in our PBR regulation recognizes that market prices do not necessarily allow unregulated firms to recover the full effect of such broad cost changes like changes in the tax law. As an example, the price in an unregulated market will not necessarily adjust for the full effect of a tax change on real property or on corporate earnings, and shareholders of unregulated firms could bear some of a tax change with the tax incidence (or impact) depending on the complex interaction of the supply and demand for both the firm's outputs and its inputs. We do understand the basis of Edison's concern and, as an example, we would certainly consider the effect of a very substantial change in regulatory law such as the introduction of a Federal value-added tax. However, we will not adopt Edison's revised criteria. Instead, we will maintain the Z-factor criteria along the lines adopted in NRF.

In D.94-06-031, we first applied the criteria described above. If we declare the event eligible for Z-factor treatment, we require that the utility incur more than the threshold cost, after which we apply the deductible to costs incurred before we allow the utility to recover any cost beyond the deductible from ratepayers. Edison has proposed a threshold and deductible of ten million dollars. On the other hand, DRA has proposed a two-tier deductible with the first tier of 20 million dollars, which shareholders bear completely, and a second tier of twenty million, which the shareholders and ratepayers split.

Edison also proposes a two-step process for the treatment of potential Z-factors as part of its PBR proposal. In the first step, Edison notifies the Commission about the existence of a potential Z-factor event. Edison then begins recording the additional expenses incurred as a result of the Z-factor event in a memorandum account. In the second step, Edison files an application in which it seeks authorization to modify PBR revenues to reflect the Z-factor event and to recover a related memorandum account balance. This filing includes testimony demonstrating that the proposed Z-factor exceeds or will exceed the $10 million threshold amount, and Edison's proposal for disposition of any balance in the memorandum account. Edison requests that the Commission adopt a quick procedural schedule, with hearings and an ALJ proposed decision within 180 days of the filing of a Z-factor application, unless a longer schedule is shown to be necessary, since costs recorded in a memorandum account may affect current earnings.

We adopt the policy underlying Edison's first step, which separately identifies the potential Z-factor costs. However, we require Edison to apply for Z-factor treatment in its annual filing for rate changes, which is consistent with D.94-06-011 (mimeo, p. 85), and we will set the Z-factor procedural schedule on a case by case basis without pre-determined deadlines.

D.2 Modification of ERAM for the Nongeneration Base Rate Revenue Requirement

In the Assigned Commissioner Ruling which required Edison to file its nongeneration PBR, we ordered Edison and other parties to propose policies for the continued use of the Electric Revenue Adjustment Mechanism (ERAM) balancing account. The ERAM balancing account allows the electric utility to recover its authorized level of base rate revenue requirement (ALBRR) when actual and expected (or forecast) sales differ; this recovery occurs through a subsequent year rate adjustment. Edison proposes the continuation of the ERAM account because it states that eliminating it would require developing policies for accounts other than ALBRR, also covered by the Energy Revenue Adjustment Billing Factor (ERABF).

As we have stated above, we prefer PBR policies which emulate the effect of the unregulated market in order to encourage the utility to manage its internal operations efficiently. In the unregulated market, the firm plans and invests to meet forecasted sales, but the firm's revenue comes from actual sales, which makes the firm face the uncertainty of sales fluctuations. In the electric utility business, the utility must plan its facilities and operations to meet forecasted customer sales under approved reliability criteria, but several effects can cause actual and forecast sales to diverge. Such effects range from daily variation in temperature, which affects air conditioning load, or less frequent variation in local economic conditions to the long term effects from trends like increased conservation efforts. The ERAM balancing account allows the utility to recover its ALBRR despite sales fluctuations due to these effects.

We order Edison to develop and include in ERAM an adjustment for the conservation effects of DSM programs. We order Edison to work with other parties in the DSM Rulemaking OIR/OII (I.91-08-002, R.91-08-003) to develop for implementation in rates by January 1, 1998, a mechanism which uses the most current ex-post measurement DSM effects to adjust for the impact of DSM through reduced sales on nongeneration base rate revenue requirement.

We order Edison to limit the scope of the ERABF to recover only the difference between the recorded and authorized nongeneration base revenue requirement attributable to the DSM mechanism described above. We may adopt a nongeneration tariff which recovers more of fixed costs through fixed charges which will limit the need for BRAM as a balancing account to recover base rate revenue requirements. We recognize the policy which we adopted in our decision, D.96-08-025, which allowed shareholders and ratepayers to share in incremental sales and where we stated that, "To the extent an overall benchmark is needed in the future in connection with these discount sales, the Commission's most recently adopted sales forecast for all customers should be used." (p.60, mimeo)

We order Edison to continue to apply the concept of the ERABF for all other accounts which currently use it, and in its compliance Advice Letter, we order Edison to file a mechanism for a surcharge, applicable to the bills of all ratepayers, to apply the ERABF to cover these accounts. We note that the size of this surcharge will vary less to the extent we move toward customer and demand charges for the collection of revenue requirement in our permanent distribution PBR.

D.3 Exclusions from the Nongeneration Base Rate Revenue Requirement

Edison has requested that we exclude certain accounts from the scope of its nongeneration PBR. Edison will exclude all generation related revenue requirements consistent with our guidelines for the definition of nongeneration base rate revenue requirements adopted above. Edison will also exclude the amounts in special one-time amortization accounts. However, where such exclusion requires development of rules which extend beyond the guidelines adopted above, we order Edison to file workpapers which support such exclusion as part of its compliance Advice Letter.

Edison shall retain the current one-way balancing account treatment for RD&D and DSM accounts which allows any reduction in spending to flow only to ratepayers. Edison shall not apply the update rule of CPI-X to the revenue requirements in these accounts.

Edison shall exclude from the nongeneration PBR the Hazardous Substance Clean-up Cost Recovery and Edison's Low Emission Vehicle programs.

We will adopt Edison's recommendation for the opening of a Catastrophic Event Memorandum Account (CEMA) to record expenses related to a qualifying disaster in accord with P.U. Code Section 454.9. However, we expect that Edison will pursue an efficient strategy to minimize such costs including the purchase of insurance and that Edison will present with its Compliance Advice Letter a report on the availability of such insurance as part of its plan to minimize the expected cost of service restoration following a catastrophic event.

We will also not accept Edison's request to exclude the cost of projects subject to Section 463, which requires a utility to submit to us for review any plans for a project whose expected cost exceeds 50 million dollars. We will allow Edison to apply for Z-factor treatment for such projects if Edison can show that the cost of such projects meets the Z-factor criteria, but we will not apply the Z-factor deductible.

We will require Edison to apply for Z-factor treatment to address the revenue requirement impact of the formation of new municipal utilities in its service territory, but we will not apply the Z-factor deductible.

E. Cost of Capital and Capital Structure

In this Section, we present our policies for the cost of capital and capital structure under the interim PBR. We will adopt Edison's proposal for a Trigger Mechanism, but we will set an effective date in a coordinated cost of capital proceeding.

E.1 The Cost of Capital Trigger Mechanism

Edison proposes to replace participation in the annual Cost of Capital proceeding with an automatic cost of capital "Trigger Mechanism." Edison asks us to adopt this Trigger mechanism not only to set the authorized return on equity but to make a corresponding revenue adjustment. We will adopt the Trigger Mechanism to reset the authorized return on the equity share of the nongeneration ratebase for the purpose of adjusting the authorized return on equity and the benchmark of the net revenue sharing mechanism.

Edison proposes to substitute its cost of capital "Trigger Mechanism" for its participation in the annual Cost of Capital proceeding. In the annual Cost of Capital proceeding, each utility submits testimony, which we use along with updated interest rate forecasts to set the authorized return on equity and the total return on ratebase. In Edison's Trigger Mechanism, Edison's authorized return on equity would change by half the change in a double A bond index value but only when the last 12 months of this index, averaged from October through September, show a cumulative change of 100 basis points from its base value. When this change occurs, it triggers Edison's authorization to file for an automatic increase in its equity return. This change also resets the base value to most recent 12 month average for the bond index. In D.96-06-055, we approved a very similar mechanism for SDG&E, filed after Edison's PBR Application and called the Market Index Capital Adjustment Mechanism (MICAM)

In one of Edison's examples, if the base bond index value were 7.5 percent and the average of the last 12 months increased to 9.0 percent (which likely means that the most current month substantially exceeds 9.0 percent), then Edison's authorized return on equity would increase by 0.75 percent or 75 basis points (half of the difference between 9.0 and 7.5) and the base index value would be reset to 9.0 percent. With a change in Edison's example if the average of the bond index value for the last 12 months increased only to 8.4 percent, no change in the authorized equity return would occur because the Trigger threshold of 100 basis points exceeds the index change of 90 basis points. However, to continue with this changed example, if the bond index then continues to increase in the following year from 8.4 to 10.0 percent, then the authorized return would rise by 1.25 percent (half the difference between 10.0

and 7.5) and the base reset to 10 percent. To vary this last example, if during the second year the bond index value declined to 7.0 percent rather continuing to rise to 10.0 percent, then Edison would again receive no change in its authorized equity return because the cumulative index value had never moved in one direction by more than 1.0 percent.

The current cost of capital proceeding allows Commission discretion and uses an interest rate forecast to set the authorized return on equity while in contrast Edison's proposal relies on an automatic rule and recent actual changes in interest rates. Edison's proposal also buffers the interest change by only allowing the authorized return on equity to change by half the change in the bond index value and only if the bond index value has changed by more than 1.0 percent. Relying on a bond index is consistent with the market's view of regulated utility stocks. Moreover, this interest rate buffering focuses on longer run changes in the interest rate, which stabilizes the authorized return, while the automatic rule removes the regulatory uncertainty in our current discretionary Cost of Capital proceeding.

The net impact of the Trigger Mechanism on shareholders and ratepayers is unclear. If we only assume that changes to a utility's authorized return represents a "zero-sum" game between shareholders and ratepayers (i.e., what's given to shareholders is taken from ratepayers), then the impact on ratepayers is unclear. However, both shareholders and ratepayers benefit from greater regulatory simplicity. The stabilizing effect of the Trigger could benefit Edison's shareholders by decreasing the long run systematic risk of Edison's equity, a potential benefit which could be shared by ratepayer and shareholder. If the inflation and interest rates are more likely to rise than fall over the duration of the Trigger Mechanism, then both the partial adjustment response to interest rate changes and the lag in the adjustment will benefit ratepayers more than shareholders. We see net benefits to ratepayers from regulatory simplicity and from potentially lower rates.

Before accepting the Trigger Mechanism, we must examine its impact within the PBR as a whole. This requires examination of the relationship between the effect of the Trigger

Mechanism and the effect of the CPI in the update rule. This update rule applies to Edison's entire nongeneration base rate revenue requirement. This base rate revenue requirement includes the return of (depreciation) as well as the return on ratebase (bond interest and the return on equity). Because the update rule equals the difference between the values of inflation and productivity indices (CPI-X), the update rule increases with inflation. For the purpose of this analysis, we can set aside the productivity adjustment because it does not change with inflation.

When applied to the base rate revenue requirement, an increase in the update rule increases the value of all base rate components, including the return on equity. The update rule adjusts the return on equity with the most recent value of inflation, which we measure with the CPI in the update rule, while the Trigger Mechanism also adjusts the return on equity by half the value of the change in the bond index, which will change to reflect expected inflation. We do recognize that inflation affects these two measures differently; the CPI reflects recent inflation and the bond index reflects expected inflation. However, we also recognize that the bond market seems particularly sensitive to the most recent changes in the CPI which indicates a link between recent inflation and the formation of expectations about future inflation.

A simple example will show the possible relationship between the effect of the CPI in the update rule and the Trigger mechanism. In the base year, assume the equity financed portion of the ratebase equals 3 billion dollars with an equity return of 300 million dollars at an assumed equity rate of 10 percent for simplicity. Assume also that current inflation as measured by the CPI rises by 3 percent and that the bond market expects this certain inflation rate will continue indefinitely which, in this example, increases the market's utility bond rate and the bond index to 13 percent. A year later, the Trigger mechanism allows the authorized return on equity to increase by only half the increase in the bond index or 150 basis points which is likely half the increase expected to clear the equity market because traditionally utility equity markets track changes in the utility bond market.

Thus, the market expects an increase of 90 million dollars at 13 percent but the utility receives only an increase of 45 million dollars because the authorized return only rises to 11.5 percent. At the same time the increase in the CPI increases the amount which the utility recovers from the 300 million in the equity return portion of revenue requirements by 3 percent from 300 to 309 million. If, as assumed in the example, inflation stays at 3 percent, then the utility will continue to receive increases in the revenue requirements from 309 to 318 to 328 to 337 to 348 million dollars in the subsequent years. The utility will reach the 13 percent rate return required in the equity market in less than 5 years. As inflation and interest rates rise, this time declines somewhat but even with an increase in the CPI of 6 percent the time is only about 4.5 years. In the meantime, the utility will not recover about 90 million dollars, half from the year delay in the implementation of the Trigger and half through the delayed effect of the increase in the application of the CPI to the equity portion of the revenue requirements. Of course, the impact of this delay on the utility is symmetric and benefits the utility when interest rates and the market return on equity decline.

We adopt the Trigger mechanism because it simplifies regulation. Ratepayers can only be worse off, if contrary to tradition, the change in the interest rate which clears the utility bond market substantially exceeds the change in return which clears the utility equity market. The Trigger mechanism can benefit ratepayers if interest rates are more likely to rise than fall.

We will decide the implementation date for the Trigger in a coordinated cost of capital proceeding. In its compliance Advice Letter, Edison must select a specific double A bond index for its Trigger mechanism. We will accept an index that shows stability in composition, has not over-reacted to changes in actual inflation and includes other integrated utilities which are representative of the existing industry and representative of structural changes likely to face Edison during electric restructuring. In its annual report, Edison should track the monthly composition of this index.

We remain concerned about the interaction about the Trigger Mechanism and the CPI. We will require Edison to show in its mid-term review that the joint effect of the Trigger Mechanism and the CPI provide an appropriate compensation for Edison's return on equity.

E.2 Capital Structure Flexibility

Edison requests that we allow it complete flexibility to change its capital structure. We will not adopt Edison's request because it could expose the ratepayer to unnecessary risk. We will adopt DRA's proposal in its testimony for limited capital structure flexibility which allows Edison to vary the share of debt or equity by no more than 5 percent from the percentage authorized in the 1997 Cost of Capital proceeding, adjusted for the share of total ratebase which is allocated to nongeneration as of January 1, 1997.

We will allow only limited flexibility in Edison's capital structure because we have not developed definitive guidelines for setting an optimal capital structure in our Cost of Capital proceedings. We have not developed these guidelines because we have not received sufficient evidence to construct such guidelines. We have received evidence which indicates that financial analysts primarily use judgment, rather than definitive guidelines, to develop recommendations to adjust capital structure. We do not object to the reliance on judgment but we believe that we should impose limits on Edison's discretion when judgment plays such a substantial role. As a simple example of the type of event we want to avoid, we do not want to authorize unlimited flexibility in capital structure which could allow a highly leveraged buyout.

E.3 Net Revenue Sharing

Edison proposes a net revenue sharing mechanism based on total system revenues (generation and nongeneration) and built around a benchmark of the total return on ratebase with shareholders receiving all gains or losses up to 150 basis points around the benchmark return and sharing equally gains or losses between 150 and 300 basis points with ratepayers. Under its proposal, shareholders receive the more achievable gains or losses. Edison also requests the right to apply for an adjustment of the PBR, including net revenue sharing, when its return falls 300 basis points below the benchmark; Edison would allow an intervention if its return rises 300 basis points above the benchmark.

In contrast, we adopt a net revenue sharing mechanism based on nongeneration revenues, not total revenues, and built around a benchmark of the authorized return on equity, not return on ratebase. The net revenue sharing mechanism must encompass the same scope of revenues and costs as the PBR itself. We have identified a separate nongeneration revenue requirement and the separation of revenue between generation and nongeneration should follow this division of base revenue requirement between generation and nongeneration. This revenue separation into generation and nongeneration is feasible because rates now include a share attributable to total base revenue requirement. When we approve separation of nongeneration into transmission and distribution, the net revenue sharing will be based on distribution revenues.

As we have described above, the Trigger mechanism will update the authorized benchmark return. We order Edison to use the authorized equity return on ratebase, not the total return, to define the benchmark. As a part of our unbundling proceeding in electric restructuring and with coordination in the cost of capital proceeding, we intend to order separate and distinct authorized equity returns for the generation, transmission and distribution operations. Under our sharing mechanism, shareholders receive all the gains and losses up to 50 basis points around the benchmark, which we call the inner band. By assigning shareholders the responsibility for all gains and losses within the inner band, we intend to assign them the gains and losses associated with routine operation. For example, we intend that this internal band include the substantial share of the revenue fluctuation due to short run temperature based sales fluctuations.

Our mechanism has a transition at 50 basis points. Between 50 and 300 basis points the shareholder share of gains or losses rises continuously from 25 through 100 percent while the ratepayer share correspondingly and continuously declines from 75 to 0 percent. We call this band in which sharing occurs, the middle band. Within these inner and middle bands from the benchmark to 300 basis points, the shareholder receives a little more than two-thirds of the net revenue and the ratepayer a little less than one-third. The shareholders receive all gains 300 basis points above the benchmark and remain responsible for all losses below 300 basis points from the benchmark, and we call this band the outer band.

We have chosen the 75/25 split at the transition from the inner to the middle band because it represents a compromise between assigning all gains or losses to ratepayers, a split of 100/0, and assigning half the gains or losses to ratepayers, a split of 50/50. A split of 100/0 would provide no marginal incentive to the shareholder while a split of 50/50 would reduce the ratepayer share of both inner and middle bands to only 20 percent which means the ratepayer receives little of the productivity gains. We have chosen to start the outer band at 300 basis points because the productivity required to reach the outer band is nearly 4 percent, adding the 300 basis points to 120 points, which is the ratebase equivalent of the 160 basis points used for the productivity or X factor.

The effect of sharing for the ratepayer is best revealed by an example. In the discussion above concerning productivity, we described an example where if Edison achieves a productivity of 3 percent, then ratepayers will receive nearly 2 percent or two-thirds of this productivity gain. In this example, assume an X value for productivity of 1.6 percent, all of which the ratepayer receives because the benchmark return incorporates the X value. Consequently, ratepayers and shareholders share productivity above 1.6 percent, which, in this example, equals 1.4 percent. The 1.4 percent applied to Edison's proposed nongeneration base rate revenue requirement of $2156 million implies about $30 million which equals about 106 basis points given Edison's proposed nongeneration jurisdictional ratebase of $2865 million.

Of this 106 basis points, shareholders receive 50 basis points from the inner band while ratepayers and shareholders split the remaining 56 basis points. On an after-tax basis, ratepayers receive 33 basis points on ratebase or 42 basis points on revenue requirement, which when combined with the 160 basis points from the X value equals 2.0 percent.[8]

Several parties call this variable sharing progressive sharing because the utility's share rises with its earned return which should give the utility an incentive to achieve greater productivity. DRA and the Joint Parties both propose progressive sharing. In contrast, parties call Edison's sharing proposal regressive because the utility's share declines with its earned return. As we have indicated above, we want to adopt a PBR which emulates the market and we conclude that progressive sharing resembles the market outcome more closely than the regressive sharing recommended by Edison.

Moreover, we have designed our net revenue sharing mechanism to complement our update rule which includes productivity values which increase over the duration of the PBR. In selecting productivity values, we recognize that we are uncertain about the exact value for achievable productivity. We have designed our progressive net revenue sharing mechanism to reveal achievable and permanent productivity gains over the duration of the PBR. This will balance the interests of the ratepayer, shareholder and employee.

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[8] To calculate the 42 basis points requires first finding the highest after-tax ratepayer share, S, of net revenue, R, given a total corporate tax rate, t, of 40 percent from (R-0.75S)(1-t) = 0.25S, which implies after-tax shares of 64 percent for ratepayers (rh) and 21 percent for shareholders (sh); second, finding the rate at which the ratepayer share declines from this maximum over the middle band range of 250 basis points which is a decline of .26 percent (dp) for each basis point increase in net revenue; third, finding the mid-point of the incremental return of 56 basis points which lies above the 50 basis point inner band (ib) or, which is 0.5(56) + 50 or 78 basis points; fourth, finding the after-tax ratepayer share which corresponds to this 78 basis point, which is rh - dp(78-ib) = 56.9 percent; fifth, calculating the ratepayer share as the product of 56.9 and 56 basis points or 31.8 basis points; and sixth translating this back to a revenue requirement basis by applying the ratio of rate base to revenue requirement or 2865/2156 which yields 42 basis points. This example contains simplifying assumptions.

To recognize the uncertainty of the effect of the PBR, we will allow Edison to apply for re-consideration of the net revenue sharing and the PBR program if its earned return falls more than 600 basis points below the benchmark and require Edison to apply if its earned return rises above 600 basis points above the benchmark. We have selected these values because they lie substantially beyond the range of the current and prospective returns for regulated electric utilities.

F. Service, Safety and Customer Satisfaction Measures

In this Section, we present our policies for service reliability, safety and customer satisfaction for the PBR. In traditional rate case regulation, we adopt a revenue requirement but we also review the utility's performance in the general rate case and in related proceedings to ensure that the utility continues to provide appropriate service and to meet health and safety objectives. Under traditional rate case regulation, our review has often emphasized more qualitative measures and we have not relied on incentives.

F.1 Service Reliability

Edison proposes to use two measures of customer service reliability. One measures the duration of service outage and the other measures the frequency of outages. In our Service Quality OII (OII.95-01-015), we have recognized that these two measures characterize service reliability and we are developing standardized measures.

Edison, DRA and IBBW each presented initial and revised proposals for service reliability incentives. These revised proposals appeared in their joint Exhibit 7B and each includes separate incentives for the duration and frequency of service outages. We will review these revised proposals.

All revised proposals accept the same scope to define the service measures and this scope excludes any event whose average customer minutes of interruption (ACMI) exceeds

5 minutes. This restriction of scope should exclude the impact of less frequent events like major storms while leaving the impact of routine events, many of which are attributable to component problems like failures (i.e., shorts) in distribution lines. Based on this restriction in scope, each party presents a performance standard and incentive mechanism. Edison and IBEW propose both rewards and penalties while DRA proposes only penalties.

To set a service reliability mechanism implies a cost-benefit analysis which compares the customer's value of service with the cost of equipment and maintenance necessary to meet the service standard. In Edison's ECAC proceedings, we use a reliability measure, the ERI, as part of the calculation of the capacity payment for QF generation, but this measure does not include a customer valuation of reliability. In PG&E's last GRC proceeding, we recognized the concept of the value of service for generation. We also note the difficulty in measuring this concept precisely. Estimating the value of service is difficult because it requires a carefully controlled survey to measure a value which can vary not only with customers but also with the level of reliability and because it requires customer valuation of a relatively infrequent event, service interruption.

The structure of the incentive depends on the value of service. For a given level of service reliability, the value of service should equal or exceed the incentive reward which, in turn, should equal or exceed the cost of providing the service. If the incentive reward were to exceed the value of service, then the utility would receive more than the customer is willing to pay for the given level of service. On the other hand, for a given level of service, the incentive penalty should equal or exceed the value of service which, in turn, should equal or exceed the cost of providing the service. If the value of service were to exceed the penalty, then the utility would pay less than the value of the service if reliability declined.

In this proceeding, no party presents a value of service study to support the size of its recommended reward or penalty incentive. In their revised testimony shown in Exhibit

7B, Edison, DRA and IBEW all recommend identical penalties and rewards of one million dollars a minute for both the duration (ACMI) and frequency incentives.

Using historical data, each incentive reward translates to a value of about 15 dollars an hours or 30 dollars combined because the two incentives are independent.[9] Given the agreement among the representative parties, we accept this value as reasonable. However, as part of its mid-term review, we require Edison to present a value of service study over a range of reliability values using a representative sample survey which controls for customer characteristics.

Before the transition to a distribution PBR, Edison will present revised estimates of historical duration and frequency performance for the distribution service only if such data are available. We will revise the service reliability mechanisms if these revised estimates change our adopted performance standards.

Moreover, we recognize that these service measures of duration and frequency will not necessarily measure some problems of deferred maintenance or failure of long-lived circuit components (e.g., if a large share of these components came on line together) and we order Edison to assemble a database with detail to the distribution circuit level which includes the date of installation for the component (or estimated average if components are grouped like the distribution circuit), and for the years of available data, a log with the date of all subsequent repair, replacement or renewal activity along with the coded nature of the reason for each such activity. Edison will present a summary description of this database at its mid-term review.

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[9] For duration, this equals the ratio of the product of one million dollars penalty per minute and the number of minutes per hour over the number of Edison customers, about 4 million or about 15 dollars per hour. For frequency, this equals the ratio of the one million dollar penalty over the product of the number of interruptions for this penalty, 183, and the average number of distribution customers per circuit, about 400, or about 14 dollars per customer interrupted, which approximately equals 14 dollars per hour given the average interruption of 59 minutes per customer.

F.1.a Service Reliability: Duration

For outage duration of ACMI, Edison proposes a performance standard of 59 minutes and DRA of 51 minutes while IBEW proposes 57 minutes in 1995, declining to 49 minutes in 1997 and 48 minutes in 1998 and beyond. All parties recognize the statistical variability of service quality measures. To acknowledge this variability, all parties include a 'deadband' around the performance standard within which no reward or penalty will apply. Moreover, all parties recommend a 2 year average for the performance standard to tie the incentive to longer term trends and to reduce the impact of random variation. As we stated, all parties propose an incentive of one million dollars per ACMI.

Edison proposes a combined reward and penalty mechanism. Based on its standard of 59 minutes of ACMI and 6 minute deadband, Edison proposes a penalty under which Edison will owe one million dollars for each minute ACMI exceeds 65 minutes up to a maximum of 83 minutes which limits the penalty to 18 million dollars. Edison also proposes a reward under which Edison will receive one million dollars for each minute ACMI declines below 53 minutes down to a minimum of 35 minutes which limits the reward to 18 million dollars.

IBEW also proposes a combined reward and penalty mechanism. Based on its standard of 49 minutes in 1997 and a deadband of 6 minutes, IBEW proposes a penalty for 1997 under which Edison will owe one million dollars for each minute ACMI exceeds 55 minutes up to a maximum of 73 minutes which like Edison's proposal limits the penalty to 18 million dollars. IBEW also proposes an initial year reward under which Edison will receive one million dollars for each minute ACMI declines below 43 minutes down to a minimum of 25 minutes which limits the reward to 18 million dollars. In 1998 and beyond, IBEW's standard declines to 48 minutes which means that the penalty starts at 54 minutes and the reward starts at 42 minutes.

DRA proposes only a penalty. Based on its standard of 51 minutes and a deadband of 11 minutes, DRA proposes a penalty under which Edison will owe one million dollars for each minute ACMI exceeds 62 minutes up to a maximum of 87 minutes which limits the penalty to 25 million dollars.

We want to encourage continued improvements in service reliability and will adopt an incentive mechanism which incorporates both rewards and penalties which is true of both the Edison and IBEW proposals. We recognize the similarity between the Edison and IBEW proposals. We adopt Edison's initial performance standard and adopt the structure of IBEW's incentive which lowers the standard over the duration of the PBR. Specifically, we adopt an initial standard of 59 minutes for 1997 and for subsequent years this standard will decline by 2 minutes a year.

We adopt a deadband of 6 minutes and a rolling 2 year average for performance measures to accommodate the year-to-year statistical variability which creates a 'small sample' problem given the relatively few years of the PBR. Using the 2-year average means that Edison will not receive rewards or owe penalties until the end of the second year of the PBR. Because we require Edison to improve its performance but again want to recognize the year-to-year variability in performance, we will not impose any penalty on Edison if it achieves an average of 55 minutes from 1997 through 2001, the 5 years of the PBR, which implies a 'true-up' of any earlier penalties. As stated above, we adopt a reward and penalty of one million dollars per minute with a maximum of 18 million dollars for both incentives. In our mid-term review, we will examine the interaction between the reliability incentives, particularly this duration mechanism, and the net revenue sharing mechanism.

F.1.b Reliability: Frequency

For outage frequency, Edison proposes a performance standard of 11,300 total interruptions per year while DRA proposes 10,800 and IBEW proposes 10,900. All parties recognize the statistical variability of service quality measures. To acknowledge this variability, all parties include a "deadband" around the performance standard within which no reward or penalty will apply. Moreover, all parties recommend a 2 year average for the performance standard to tie the incentive to longer term trends and to reduce the impact of random variation. As we stated, all parties propose the same incentive of one million dollars per 183 annual interruptions.

Edison proposes a combined reward and penalty mechanism. Based on its standard of 11,300 annual interruptions and an 1,100 annual interruption deadband, Edison proposes a penalty under which Edison will owe one million dollars for each 183 interruptions which exceed 12,400 up to a maximum of 15,700 annual interruptions which limits the penalty to 18 million dollars. Edison also proposes a reward under which Edison will receive one million dollars when interruptions decline below 10,200 up to a minimum of 6,900 annual interruptions which limits the reward to a maximum of 18 million dollars.

IBEW also proposes a combined reward and penalty mechanism. Based on its standard of 10,900 annual interruptions and an 1,100 annual interruption deadband, IBEW proposes a penalty under which Edison will owe one million dollars for each 183 interruptions which exceed 12,000 up to a maximum of 15,300 annual interruptions which limits the penalty to 18 million dollars. IBEW also proposes a reward under which Edison will receive one million dollars when interruptions decline below 9,800 up to a minimum of 6,500 annual interruptions which limits the reward to a maximum of 18 milllion dollars.

DRA proposes only a penalty. Based on its standard of 10,800 interruptions and a deadband of 2,200 interruptions, DRA proposes a penalty under which Edison will owe one million dollars for 183 interruptions which exceed 13,000 up to a maximum of 17,600 which limits the penalty to 25 million dollars.

We want to encourage continued improvements in service reliability for both frequency as well as duration and will adopt an incentive mechanism which incorporates both rewards and penalties which is true of both the Edison and IBEW proposals. We recognize that the Edison and IBEW proposals are identical except for the performance standard with IBEW proposing 10,900 and Edison proposing 11,300. We adopt IBEW's entire proposal with its somewhat more aggressive performance standard of 10,900. Again, we adopt the concept of a deadband and a 2-year average for the performance measures to accommodate the year-to-year statistical variability which creates a 'small sample' problem given the relatively few years of the PBR. Using the 2-year average means that Edison will not receive rewards or owe penalties until the end of the second year of the PBR. As stated above, we adopt a reward and penalty of one million dollars per 183 interruptions with a maximum of 18 million dollars for both incentives.

F.2 Customer Satisfaction

Edison recognizes that physical reliability represents an important, but not the only, measure of performance. Customers contact Edison offices for several types of service, including service connection, meter installation and performance, line problems, tariff options and billing problems. To ensure continued adequate customer service in contacts with its offices, Edison proposes an incentive for customer satisfaction.

Edison proposes to use the results of its ongoing customer survey program to measure customer satisfaction. This survey program, initiated in 1992, uses a sample of customers with recent customer contacts and surveys in five areas: field service and meter reading operations; local office operations; telephone center operations; service planning activities and energy service representative activities. Edison proposes to use the first four areas in its customer satisfaction incentive.

In each of the areas surveyed, Edison asks a variety of questions, including a question which asks the respondent's overall satisfaction with the specific service provided. Respondents choose among six categories with the top two being "completely satisfied" and "delighted." Edison measures its performance based on the percentage of responses which fall into the top two categories on the survey question which asks about the degree of overall satisfaction. In the baseline survey, 64% of responses rated Edison in the top two categories using a simple average across the four service areas. Edison proposes to use this baseline response as its performance standard.

Edison designed the survey for internal management feedback to identify actions which can improve customer satisfaction. Therefore, specific survey questions and the areas surveyed may vary over time. However, Edison pledges that it will not change the six-point scale or the overall satisfaction question which is the basis for the performance standard, so these aspects of the surveys should remain comparable throughout the PBR.

TELACU expressed a concern that telephone-based surveys may not adequately represent low-income customers without telephone service or non-English-speaking customers. Edison responds that it tested its existing survey procedures to determine whether they are biased because some customers lack telephones or speak languages other than English or Spanish, the two languages used in the surveys.

In its rebuttal testimony, Edison significantly modified its service quality proposal to reflect recommendations made by IBEW. Edison envisioned its original service quality proposal as providing a guarantee to maintain historic levels of performance. In Exhibit 7B, Edison proposes a 64 percent performance standard with a 3 percent deadband and a 5 percent reward and penalty band. This implies a reward from 67 to 72 percent and a penalty from 61 to 56 percent with the incentive being set at 2 million dollars for each percentage point allowing a maximum reward or penalty of 10 million dollars.

IBEW's proposal includes a higher performance standard of 67 percent, and also uses a 3 percent deadband and a 5 percent reward and penalty band. IBEW also accepts Edison's incentive of 10 million dollars or 2 million dollars for each percentage point. However, IBEW proposes an area specific penalty for each of the four separate service areas which Edison surveys which would penalize Edison by 2 million dollars for each percentage point that the performance measure fell below 61 percent in any area. IBEW maintains the overall maximum penalty of 10 million dollars across both the combined and individual service area performance.

DRA accepts many of IBEW's recommendations. DRA proposes a performance standard of 64 percent like Edison and a deadband of 3 percent with its penalty starting at 60 percent. DRA proposes a graduated penalty, increasing from one million dollars at 60 percent, 5 million at 59 percent, 10 million at 58 percent, 15 million dollars at 57 percent and 20 million at 56 percent. DRA also proposes an area specific penalty if the performance falls below 55 percent. Moreover, DRA expresses concern about relying exclusively on Edison's customer satisfaction survey as the only measure of customer satisfaction, and DRA also notes that Edison controls the survey instrument and its use which concerns us.

We note that the IBEW and Edison proposals for the combined service areas are identical except for the performance standard with Edison recommending the historic standard of 64 percent and IBEW recommending an increased standard of 67 percent. We received no testimony which indicated the measures which Edison would need to undertake to raise the standard. Moreover, we are concerned that this standard is entirely subjective with responses like "completely satisfied" and "delighted" varying with respondent as well as with the nature of the service contact. Therefore, we will adopt the historic performance standard. However, we will adopt IBEW's proposal for a penalty in each service area because we want Edison to offer comparable service in all areas. Moreover, we are concerned about Edison receiving a reward when a substantial share of its customers express some dissatisfaction and we will make any reward conditional on no more than 10 percent of customer responses being in the bottom two of the six categories.

We support DRA's concern that Edison's own marketing Department conducts this survey and we order Edison to include with its compliance filing a plan to use an outside survey firm to confirm a representative sample of its customer responses. Moreover, for the mid-term review, we order Edison to develop a more objective measure of customer satisfaction which includes such aspects as response time, problem resolution and customer comparison with similar service contacts and which ensures that Edison's internal and external measures of performance are consistent.

F.3 Health and Safety Mechanism

Both Edison and IBEW presented an employee health and safety incentive. The standard consists of a ratio index of the total number of accidents and illnesses per 200,000 hours worked or per 100 employees. Edison proposes an index standard of 13.5, based on the most recent 10 years of data while IBEW proposes an index standard of 13.0 based on the most recent 7 years of data. IBEW proposes a deadband of 0.3 and Edison a deadband of 0.8.

IBEW recommends a penalty which applies to the range from 13.3 to 14.2 in the index value with a penalty incentive of 555 thousand dollars for each 0.1 increase in the performance index, and IBEW also proposes a reward which applies to the range from 11.8 to 12.7 using its same incentive. Edison recommends a penalty which applies to the range from 14.3 to 16.7 in the index value with a penalty incentive of 208 thousand dollars for each 0.1 increase in the performance index, and Edison also proposes a reward which applies to the range from 10.3 to 12.7 using its same incentive.

We prefer IBEW's proposed standard because the slightly lower injury and illness frequency rate benchmark best reflects our commitment to the maintenance of health and safety standards. However, we note that this index does not weigh accidents by the severity of their impact (e.g., in terms of lost workdays) and that disputes may arise in deciding whether to attribute the cause of an illness to the workplace. We order Edison to review these issues in its mid-term review.

F.4 National Bill Comparison Mechanism

In its comments filed in response to D.95-12-063 our Electric Restructuring Policy Decision, Edison withdrew this proposed mechanism from consideration as part of a distribution PBR. Given the overall rate cap adopted as part of that Decision, we will not adopt a national bill comparison mechanism in this Decision. We note that such a mechanism should compare the rates of Edison's distribution business with other distribution businesses offering a similar scope of services but few such electric distribution businesses offer separate rates in today's market. We anticipate that electric restructuring in other states will create more separate distribution businesses but the nature and scope of the services offered by such businesses is now unknown.

G. Monitoring and Reporting

In this Section, we describe monitoring and reporting requirements for Edison's nongeneration and distribution PBRs. For Edison, a rate base PBR is a new form of regulation.

When we substantially change the form of regulation, we must carefully assess the impact on both ratepayers and the utility. To assess the impact requires clear and measurable objectives. We have adopted a PBR which has clear standards in both rate and service incentive mechanisms. For rate performance, we have adopted an update rule of CPI-X and progressive net revenue sharing. For service performance, we have adopted two direct measures of service reliability and a measure of customer satisfaction. We have adopted the standards in these incentive mechanisms after an assessment of their prospective impact.

We will not adopt other rate or service performance standards which have a direct financial incentive because we intend to initiate the PBR with complete and comprehensive performance standards. However, we recognize that we have adopted a PBR which has relatively few rules. Moreover, we recognize that the PBR, as a new form of regulation, will affect many aspects of the utility's operation which the PBR does not directly measure and could generate unintended consequences, as well, which impact both the utility and ratepayers.

We order Edison to convene a working group process which will assess the need for any additional standards for evaluation. We are not requesting that this working group develop new incentive mechanisms. We suggest that this group focus initially on at least these two issues: from the customer's perspective whether the reliability and customer incentives are sufficiently comprehensive and protective (e.g., does the Commission need area-specific reports on the duration and frequency of outages) and from both the utility's and the customer's perspective under what circumstances could conflict arise among the PBR incentive mechanisms. We ask the working group to report back to us by mid-1997. Later after the utilities have filed their unbundling proposals in electric restructuring, we ask this working group to assess the desirability of a comprehensive unit cost accounting system which could identify distribution services which Edison can eventually unbundle and which could track costs from inputs to outputs.

We order Edison to submit an annual report which is similar to the report filed by SDG&E in its compliance with D.94-08-023 and entitled "Compliance with D.94-08-023 SDG&E's Performance Based Ratemaking (PBR) Base Rate Mechanism", dated May 15, 1996. In its compliance Advice Letter filing, Edison shall explain why it should not submit the reports required of SDG&E as part of D.94-08-023.

H. Implementation

We order Edison to make a compliance Advice Letter filing no later than 30 days of the effective date of this decision. The Advice Letter shall incorporate the following provisions. The PBR shall be effective on January 1, 1997. Edison will file an interim report on March 1, 1999. Edison shall submit the reports described in this decision as part of the midterm review with this interim report. The Commission will review the report and perform a midterm evaluation of the operation of the PBR between March and December 1999, and will issue a midterm decision by December 1999. The midterm decision will set further guidelines for remaining evaluation and reporting.

Findings of Fact

1. On December 23, 1993, Edison filed A.93-12-029 (PBR Application) proposing an integrated Base Rate PBR Mechanism for generation, transmission, and distribution services.

2. On April 6, 1994, in response to a motion by TURN, we issued I.94-04-003 which provided that alternatives to Edison's PBR proposal could be considered in the course of review of Edison's PBR Application.

3. PBR, if properly designed, would be more compatible with competitive energy markets than traditional regulation, would assist utilities in making the transition to competition, would provide strong incentives for cost reductions, and promises to simplify regulation and reduce administrative burdens.

4. On July 12, 1994, Assigned Commissioner Fessler issued a Ruling that bifurcated the hearings of Edison's PBR Application into two phases to address the uncertainty associated with the Commission's ultimate disposition of the issues raised in the Blue Book.

5. On August 8, 1994, Edison filed its Phase I Nongeneration PBR proposal.

6. To encourage efficiency, effective PBR regulation breaks the feedback link from costs to rates and includes an incentive for the utility to reduce costs.

7. Effective PBR regulation must include appropriate standards for service and safety.

8. In D.89-10-031, we adopted a form of PBR regulation, first used in the United Kingdom, and often called 'CPI - X' regulation, where CPI updates rate for the effect of inflation and X updates rates for the effect of productivity.

9. In D.89-10-031, we also adopted a net revenue sharing rule which allows the utility to keep some of the increased net revenue which occurs if the utility can reduce its costs. Adoption of this rule should increase the utility's incentive to reduce costs. PBR emulates the competitive process to encourage utility management to make decisions which resemble an efficient or competitive outcome.

10. FERC and NARUC guidelines provide criteria with which we can separate ratebase between generation and nongeneration.

11. Transmission and distribution operation and maintenance expenses belong to nongeneration.

12. Customer accounts should be assigned to nongeneration because most customer account costs such as opening and closing accounts, changing service or tariff billing and responding to customer billing problems vary with customer requirements.

13. Administrative and general functions provide support for labor activity throughout the utility.

14. In Edison's 1995 GRC, RD&D was allocated 47 percent to nongeneration and 53 percent to generation.

15. FERC and Commission Decisions allocate franchise fees to nongeneration as a local expense.

16. Uncollectibles vary with total revenue and therefore with total other expenses.

17. In D.96-01-011, we adopted an authorized level of base rate revenue requirement (ALBRR) of $4,017 million and we removed the base rate revenue requirement associated with SONGS 2&3 in D.96-04-059.

18. To adopt a rate PBR for nongeneration requires determining separate rates for nongeneration and generation base rate revenue requirement. To accomplish this requires separating all existing rates and charges which recover base revenue requirement into rates and charges that separately recover generation and nongeneration base revenue requirement.

19. In D.96-01-011, we required Edison to file an Application if it requested an adjustment for inflation. We will treat Edison's PBR Application as an application for this purpose and will allow Edison to apply the CPI-X update rule effective January 1, 1997, for nongeneration rates effective in 1997.

20. In Order 888, FERC established seven criteria for the functional separation of transmission and distribution components and, therefore, ratebase. In its FERC filing made on April 29, Edison requested that FERC declare transmission facilities as those carrying voltages 230kV or higher. FERC's approval of the supporting ratebase and revenue requirement must also occur well before January 1, 1998, to allow Edison, PG&E and SDG&E to complete their distribution PBR filings here. FERC's approval of the ratebase and revenue requirement for transmission will help us make a final determination of the initial value of the distribution ratebase and revenue requirement for each utility.

21. Over the past decade the CPI has tracked the Wholesale Price Index.

22. Use of the CPI provides a general and usually much less controversial choice as proxy for a utility's input prices.

23. Edison's study of total factor productivity for its entire (generation and nongeneration) system presented in its 1995 Test Year General Rate Case, verified by DRA through its own independent analysis, reported a value of 1.4 percent while Edison's study of total factor productivity for its nongeneration business presented in Edison's revised PBR Application in August, 1994, reported a value of 0.9 percent.

24. In D.89-10-031, we recognized that unexpected events, which we labelled Z-factors, could lead to changes in the utilities' costs, some of which we would want included in the utilities' revenue requirements and some of which we would not.

25. In D.94-06-011, we adopted nine criteria to assess whether a Z-factor occurred.

26. The ERAM balancing account allows the utility to recover its ALBRR despite sales fluctuations.

27. Edison proposes to replace participation in the annual Cost of Capital proceeding with an automatic cost of capital "Trigger Mechanism".

28. In Edison's Trigger Mechanism, Edison's authorized return on equity would change automatically by half the change in a double A bond index value but only when the average of the last 12 months' index value has changed by at least 100 basis points.

29. Edison requests that we allow it complete flexibility to change its capital structure.

30. Edison proposes a net revenue sharing mechanism based on total system revenues (generation and nongeneration) and built around a benchmark of the total return on ratebase with shareholders receiving all gains or losses up to 150 basis points around the benchmark return and sharing equally gains or losses between 150 and 300 basis points with ratepayers.

31. For outage duration or ACMI, the historical performance is 59 minutes for the past 10 years.

32. For system interruptions, Edison proposes 11,300 interruptions, IBEW 10,900 and DRA 10,800 for the performance standard.

33. For the customer satisfaction survey, the historical performance is 64 percent.

34. For the health and safety index, the historical performance is 13.0 for 7 years and 13.5 for 10 years.

Conclusions of Law

1. A rate PBR does not require a sales forecast because a rate PBR simply updates current rates with CPI-X to determine future rates, which eliminates the controversy of sales forecasts or balancing accounts such as ERAM.

2. The CPI should be used as the price index for the nongeneration and distribution PBRs.

3. We adopt a productivity measure which starts with a value of 1.2 and increases by 0.2 percent a year for the next two years. Thus, we order productivity or X values of 1.2 for 1997, 1.4 for 1998, and 1.6 for 1999 through 2001. These values will apply to both the nongeneration PBR and its successor, the distribution PBR.

4. We will maintain the nine Z-factor criteria developed in D.94-06-011. We will adopt Edison's threshold and deductible of ten million dollars.

5. The ERABF should recover only the difference between recorded and authorized nongeneration base revenue requirement attributable to DSM.

6. The Trigger mechanism should be used to update the authorized return on equity for the purpose of updating the net revenue sharing benchmark and for revenue requirement recovery.

7. Edison's request for unlimited flexibility in its capital structure exposes ratepayer to possible undesirable financial risk.

8. The net revenue sharing mechanism should be based on nongeneration revenues and built around a benchmark of the authorized return on equity. By assigning shareholders the responsibility for all gains and losses within the inner band, we intend to assign them the gains and losses associated with routine operation. At the transition from the inner band to the middle band, a split of 100/0 would provide no marginal incentive to the shareholder while a split of 50/50 would reduce the ratepayer share of both inner and middle bands to only 20 percent which means the ratepayer receives little of the productivity gains. We have chosen to start the outer band at 300 basis points because the productivity required to reach the outer band is over 4 percent.

9. Our progressive net revenue sharing mechanism should reveal achievable and permanent productivity gains over the duration of the PBR and should balance the interests of the ratepayer, shareholder and employee.

10. The PBR should encourage continued improvements in service reliability and an incentive mechanism should incorporate both rewards and penalties.

11. IBEW's proposed standard with its slightly lower injury and illness frequency rate benchmark best reflects our commitment to the maintenance of health and safety standards.

Order

IT IS ORDERED THAT:

A. Edison shall file an Advice Letter no later than 30 days following the effective day of this decision which shall include the following provisions:

1. Edison shall separate its generation and nongeneration base rate revenue requirements by allocating:

a) Transmission and distribution O&M to nongeneration;

b) Customer accounts to nongeneration;

c) CS&I costs to generation except economic development costs to nongeneration;

d) Administrative and general to generation and nongeneration using a labor allocation;

e) RD&D 47 percent to nongeneration and 53 percent to generation;

f) Uncollectibles to generation and nongeneration based on total other expenses;

g) Property and related taxes based on net plant.

2. Edison shall separate its generation and nongeneration ALBRR after making all adjustments which we have ordered since Edison filed its PBR Application.

3. Edison shall separate all existing rates and charges which recover base revenue requirement into rates and charges that separately recover generation and nongeneration base revenue requirement.

4. Edison shall apply the CPI-X update rule effective January 1, 1997, for nongeneration rates effective in 1997.

5. Edison shall file a price PBR with a CPI-X update rule.

6. Edison shall use the CPI as the measure of inflation in the update rule for both its nongeneration and distribution PBRs.

7. Edison shall use the following values for productivity or X in the update rule for both its generation and distribution PBRs: 1.2 in 1997; 1.4 in 1998; 1.6 in 1999 through 2001.

8. Edison shall use the Z-factor standards based on the nine Z-factor criteria developed in D.94-06-011 and a threshold and deductible of ten million dollars. Edison shall use a process for accounting, assessing and adjudicating a Z-factor claim which is consistent with D.94-06-011.

9. Edison shall limit the scope of the ERABF to recover only the difference between the recorded and authorized nongeneration base revenue requirement due to the adopted DSM adjustment mechanism.

10. Edison shall develop and include in ERAM a DSM adjustment mechanism, which uses the most current ex-post measurement effects to adjust for the conservation impact of DSM programs on nongeneration base rate revenue requirement.

11. Edison shall continue to use ERAM and apply ERABF for all other accounts which currently use it, and include a mechanism for a surcharge, applicable to the bills of all ratepayers, to recover the revenue requirements for these accounts.

12. Edison shall exclude from the scope of this nongeneration PBR all generation related revenue requirements consistent with our guidelines for the definition of nongeneration base rate revenue requirements adopted above. Edison shall exclude the amounts in special one-time amortization accounts.

13. Edison shall retain the current one-way balancing account treatment for RD&D and DSM accounts which allows any reduction in spending to flow only to ratepayers and Edison shall not apply the update rule of CPI-X to the revenue requirement for these accounts.

14. Edison shall exclude Hazardous Substance Clean-up Cost Recovery and Edison's Low Emission Vehicle programs from the nongeneration PBR.

15. Edison shall open a Catastrophic Memorandum Event Account in accord with P.U. Code 454.9 to record costs related to a catastrophic event, and Edison will submit a report which will describe the availability of catastrophic event insurance.

16. Edison's shall use the Z-factor process without the deductible for projects subject to Public Utilities Code Section 463. Edison shall use the Z-factor process without the deductible to address the revenue requirement impact of the formation of new municipal utilities.

17. Edison shall use its Trigger mechanism to update the authorized return on equity for the purpose of updating the net revenue sharing benchmark and for revenue requirement recovery.

18. Edison shall limit its capital flexibility for debt and equity to within 5 percentage points from that adopted in the 1997 Cost of Capital proceeding, adjusted for the share of total ratebase which is allocated to nongeneration as of January 1, 1997.

19. Edison shall use a net revenue sharing mechanism based on nongeneration revenues and built around a benchmark of the authorized return on equity. The net revenue sharing mechanism shall encompass the same scope of revenues and costs as the PBR itself. Edison shall use the authorized equity return on ratebase to define the benchmark. Shareholders shall receive all the gains and losses up to 50 basis points around the benchmark, which we call the

inner band. Between 50 and 300 basis points the shareholder share of gains or losses shall rise continuously from 25 through 100 percent while the ratepayer share shall correspondingly and continuously decline from 75 to 0 percent. We call this band in which sharing occurs, the middle band. The shareholders shall receive all gains 300 basis points above the benchmark and remain responsible for all losses below 300 basis points from the benchmark, and we call this band the outer band. We will allow Edison to apply for re-consideration of the net revenue sharing and the PBR program if its earned return falls more than 600 basis points below the benchmark and require Edison to apply if its earned return rises above 600 basis points above the benchmark.

20. In its service reliability standard for ACMI, Edison shall use an initial standard of 59 minutes in 1997 declining by 2 minutes for each subsequent year, shall use a deadband of 6 minutes and shall use a rolling 2 year average. Edison shall not receive a penalty if it achieves an average of 55 minutes from 1997 through 2001, the 5 years of the PBR. Edison shall use a reward and penalty of one million dollars per minute with a maximum of 18 million dollars.

21. In its service reliability standard for frequency, Edison shall use a standard of 10,900 interruptions with a deadband of 1,100 and a rolling 2-year average. Edison shall use a reward and penalty of one million dollars per 183 interruptions with a maximum of 18 million dollars.

22. For customer satisfaction, Edison shall use the historic performance standard of 64 percent, a deadband of 3 percent and use a reward and penalty of 2 million dollars for each percentage point with a maximum of 10 million dollars, and shall apply a penalty in each service area because we want Edison to offer comparable service in all areas. Edison shall not receive a reward if the percent of customers in the bottom two categories exceeds 10 percent. Edison shall use an outside survey firm to confirm a representative sample of its customer responses.

23. For employee health and safety, Edison shall use a penalty which applies to the range from 13.3 to 14.2 in the index value with a penalty incentive of 555 thousand dollars for each 0.1 increase in the performance index : nd a reward which applies to the range from 11.8 to 12.7 using the same incentive.

This order is effective today.

Dated September 20, 1996, at San Francisco, California.

P. GREGORY CONLON
President
DANIEL Wm. FESSLER
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

We will file a joint concurring opinion.

/s/ P. GREGORY CONLON
President

/s/ JESSIE J. KNIGHT, JR.
Commissioner

A.93-12-029
D.96-09-092

COMMISSIONERS JESSIE J. KNIGHT AND P. GREGORY CONLON, CONCURRING:

Although we are supporting this alternate decision, we both would have a preferred a Performance Based Ratemaking (PBR) mechanism that would have imposed a significantly higher annual productivity factor upon the company, probably in the range of 2% per year.

In our minds, the productivity factors of 1.2% to 1.6% adopted in this decision represent a continuation of business as usual. They are not sufficient to bring about a paradigm shift in how the company behaves and acts. The adopted productivity factor is not sufficient in forcing the company to make fundamental changes in corporate culture and strategy as it emerges into the new competitive environment.

In exchange for the higher productivity, we would have considered giving the company a wider band on the earnings or losses that they would be responsible for achieving.

In our minds, some of these issues can be revisited when we have the mid-course review of the PBR mechanism 2 1/2 years from now. For that reason, we both support this item.

San Francisco, California
September 27, 1996

/s/ Jessie J. Knight
JESSIE J. KNIGHT,
Commissioner

/s/ P. Gregory Conlon
P. GREGORY CONLON,
President

A.93-12-029

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Commissioner

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P. GREGORY CONLON,
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