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Decision 97-08-056 August 1, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Identify and Separate Components of Electric Rates, Effective January 1, 1998. (U-39 E)	Application 96-12-009 (Filed December 6, 1996)
Application of San Diego Gas & Electric Company (U 902-M) for Authority to Unbundle Rates and Products.	Application 96-12-011 (Filed December 6, 1996)
In the Matter of the Application of Southern California Edison Company (U 388-E) Proposing the Functional Separation of Cost Components for Energy, Transmission, and Ancillary Services, Distribution, Public Benefit Programs and Nuclear Decommissioning To Be Effective January 1, 1998 in Conformance with D.95-12-036 as Modified By D.96-01-009, the June 21, 1996 Ruling of Assigned Commissioner Duque, D.96-10-074 and Assembly Bill 1890.	ORIGINAL Application 96-12-019 (Filed December 6, 1996)

(See attached service list for appearances.)

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OPINION

Summary

This decision resolves issues relating to the allocation of costs between the various functions of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). It also allocates revenues between customer classes within each function and establishes certain rate design principles.

This process of "unbundling" utility rates and services is integral to the Commission's implementation of electric industry restructuring.

I. Procedural Background

A. Electric Restructuring Policy and Decisions

This proceeding is part of the Commission's larger effort to promote competition in electric generation markets. Decision (D.) 95-12-063, as modified in D.96-01-009, set forth in general terms the Commission's policy in matters concerning electric industry restructuring. That order acknowledged that under the new market structure electric system transmission would be regulated by the Federal Energy Regulatory Commission (FERC) and that distribution would remain under the Commission's jurisdiction. The order identified the need to disaggregate electric utility rates by "unbundling" generation, transmission and distribution for all all direct access customers. This proceeding is the Commission's forum to accomplish such unbundling.

A series of rulings provided guidance to the utilities with regard to the scope of their applications to unbundle their system rates. On September 23, 1996, Assembly Bill (AB) 1890 became law, generally codifying the restructuring plan set forth in D.95-12-063. That legislation established a Power Exchange (PX), through which electricity could be purchased and sold, and the Independent System Operation (ISO), which would dispatch and manage the transmission system.

Subsequently, the Commission issued D.96-10-074 specifying the extent of cost separation to be addressed in the utility applications. It ordered each utility to separate its last authorized rate base and revenue requirement into generation, transmission, and distribution consistent with the anticipated FERC order on transmission revenue requirement. On March 31, 1997, the ISO and PX trustee filed tariffs and other documents at the FERC in order to create the ISO and PX by January 1, 1998. The utilities filed proposals for their respective transmission revenue requirements at the FERC concurrently.

B. The Unbundling Proceeding

On December 6, 1996, PG&E, Edison and SDG&E filed these applications in separate dockets. The three dockets were consolidated to facilitate review. On January 31, 1997, the Administrative Law Judge (ALJ) issued a ruling defining the scope of the proceeding and addressing other procedural matters. In accordance with the ruling, utilities served supplemental testimony on February 14. Other parties served testimony on February 28. The Commission held evidentiary hearings for 15 days from March 24 through April 14 at which 53 witnesses testified on behalf of 18 parties.

The active parties other than the utilities are Office of Ratepayer Advocates (ORA), the California Energy Commission (Energy Commission), Agricultural Energy Consumers Association (AECA), Bay Area Rapid Transit (BART), California City-County Street Light Association (CAL-SLA), California Building Industry Association (CBIA), California Farm Bureau Federation (Farm Bureau), California Industrial Users (CIU), California Large Energy Consumers Association (CLECA), California Manufacturers Association(CMA), California Mobilehome Resource and Action Association, Inc. (CMRAA), Cogeneration Association of California (CAC), Energy Producers and Users Coalition (EPUC), Department of Defense/Department of the Navy/Federal Executive Agencies (DOD), Enron and its affiliate Enron Capital and Trade Resources (Enron), Southern Energy Retail Training and Marketing (Southern), The Utility Reform Network (TURN), Utility Consumers Action Network (UCAN), and Western Mobilehome Parkowners Association (WMA).

On March 19, the utilities, ORA , CIU, CLECA, CMA, and DOD filed their Joint Motion for Adoption of Retail Transmission Rate Stipulation, together with the

Retail Transmission Rate Stipulation dated March 19. No party filed comments on the motion or opposed it.

On April 30, parties filed opening briefs. On May 9, 1997, parties filed reply briefs and the matter was submitted.

II. Scope and Purpose of the Proceeding

The primary purpose of this proceeding is to unbundle the three utilities' revenue requirements into major functions in order to promote competition in electrical generation markets. Specifically, we (1) identify separate revenue requirements for distribution; (2) allocate costs of these functions to the various customer classes, and (3) address corresponding rate design principles. We also establish a revenue requirement and cost allocation for public benefit programs consistent with AB 1890.

A secondary objective of this proceeding is to determine the information the utilities must provide on their customer bills beginning with the introduction of direct access on January 1, 1998. The success of direct access depends largely on customers having information that permits them to make reasoned choices about electricity purchases.

The parties also addressed the issue of whether tariffs for master meter customers should be changed in light of direct access.

In addressing the subjects appropriately within the scope of this proceeding, it is useful to identify those issues that are not addressed here and that are subjects of other proceedings. The Commission has already issued D.97-05-039, in which we resolved issues relating to billing and metering.

Costs which are associated with uneconomic generation are addressed in the Electric Restructuring Rulemaking (R.)94-04-031/Investigation (I.) 94-04-032. Load profiling is properly the subject of the Direct Access which is also addressed in, R.94-04-031/I.94-04-032. That proceeding is also the appropriate forum for considering mobilehome park tenants' eligibility for direct access. Performance-based ratemaking (PBR) proposals are under consideration in the related proceedings of individual utilities. The revenue bonds which the utilities will issue to finance the rate reductions mandated by AB 1890 are being considered in separate applications filed by each utility.

III. Retail Transmission Rate Stipulation

On March 19, 1997, several parties filed with the Commission a "Joint Motion for Adoption of Retail Transmission Rate Stipulation." The stipulation was signed by CIU, CLECA/CMA, DOD, ORA, PG&E, SDG&E, and Edison. The stipulation makes three recommendations. It asks the Commission to support the position that the FERC defer to the Commission's recommendations regarding the design of rates for unbundled retail transmission service. It recommends that the Commission adopt in this proceeding the retail transmission revenue allocation and rate design methods included in the utilities' December 6, 1996 filings, supplemented by Appendix A to the stipulation. Finally, it recommends that the Commission file comments with FERC supporting a request that FERC defer to the Commission's recommendations for developing revenue allocations and rate design for unbundled retail transmission service for at least the first two years after implementation of the new industry structure.

No party protested either the joint motion or the elements of the stipulation. On June 5, 1997, the Commission filed comments in the FERC dockets addressing these issues. In the filing, we stated our support for the proposition that FERC should to defer to our recommendation regarding revenue allocations and rate design for unbundled retail transmission service, as the stipulation proposes. (See "Notice of Limited Protest, request for Hearing and Request for Deference to the Public Utilities Commission of the State of California on Rate Design and Cost Allocation for Retail Transmission Customers," in Docket Nos. ER97-2358-000, ER97-2364-000 and ER97-2355-000. Also see "Initial Comments of the Public Utilities Commission of the State of California on the March 31, 1997, Phase II Filings," in Dockets EC96-19-003 and ER96-1663-003.) Our recommendation came in response to the stipulation and in recognition that the FERC and this Commission have relied upon different approaches for wholesale and retail ratemaking, respectively. The application of those differing approaches as to retail rates might result in significant shifts in cost responsibility between retail customer classes. AB 1890 explicitly prohibits such cost shifting (see Public Utilities (PU) Code §§ 330, 367(e)).[1] At the time we filed our comments at FERC, we had not yet formulated such recommendations which are the subject of this order and so did not comment on the methods proposed by the stipulation.

The Commission's most recently adopted revenue allocation methodologies determine marginal costs for each customer class and then reach the adopted revenue requirement by increasing (or decreasing) the rate by an equal percent of marginal cost for each class.

Edison proposes to apply this "equal percentage of marginal cost" (EPMC) methodology on the basis of total revenues instead of by functions, as PG&E and SDG&E propose.

ORA supports Edison's EPMC method, arguing that the methods proposed by PG&E and SDG&E are equivalent to an embedded costs allocation.

CAL-SLA supports PG&E's approach, believing it provides for an allocation that is proportional to the existing revenue requirement.

In the decision in which we adopted long-run marginal costs for gas prices, the Commission found that applying the EPMC method on a functional basis is, as ORA observes, essentially applying an embedded cost method. We reject such an approach, consistent with our view that EPMC is superior in moving utility prices toward those that would be found in competitive markets. We adopt ORA's recommendation and direct all three utilities to use Edison's EPMC approach in allocating costs between customer classes.

IV. Criteria for Evaluating Unbundling Proposals

The purpose of unbundling, as we have stated many times, is to promote the development of competitive markets for generation services. The purpose of

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[1] All section references are to the Public Utilities Code unless otherwise indicated.

promoting competition where it may be viable is to assure the best use of the economy's resources, to assure customers pay the lowest price for services, and to expand the array of services available to customers. Unbundling promotes competition by providing customers with options for individual services and sending customers price signals which would permit them to make reasoned choices about their competitive options. We accomplish unbundling the various utility functions with certain more specific criteria guiding our assessments.

A. *Unbundling Must Be Consistent With the Spirit and Letter of AB 1890 and Other Relevant Law*

AB 1890 set the state on a course of electric industry restructuring which this proceeding in part implements. AB 1890 recognized that "in order to achieve meaningful wholesale and retail competition in the electric generation market, it is essential to...(s)eparate monopoly utility transmission functions from competitive generation functions...." (PU Code § 330(k)(1).) More specifically, the statute directs the Commission to review utility cost recovery plans which must "provide for identification and separation of individual rate components such as charges for energy, transmission, distribution, public benefit programs, and recovery of uneconomic costs." (PU Code § 368(b).) D.96-12-077 approved those plans as an interim step towards the process of unbundling which we continue in more detail here.

In providing for unbundled rates, AB 1890 prevents discriminatory ratesetting by providing that "the separation of rate components required by this subdivision shall be used to ensure that customers of the electrical corporation who become eligible to purchase electricity from suppliers other than the electrical corporation pay the same unbundled component charges, other than energy, a bundled service customer pays." (§ 368(b).) The section continues "(n)o cost shifting among customer classes, rate schedule, contract, or tariff options shall result from the separation required...."

Finally, AB 1890 provides for recovery of costs associated with public benefit programs by way of a separately identified charge. (See § 381.)

We proceed with these and related requirements as the foundation for our analysis of parties' proposals.

B. Costs Associated With One Function Will Not Be Allocated to Other Functions

Unbundling utility rates and services is one of the primary means by which efficient markets may develop for utility products and services. That is, to the extent that prices reflect the costs of associated products and services, sellers will offer the most efficient quantity and variety of these products and services. Buyers will then be able to make purchasing decisions that best serve their interests.

In pursuing a policy to promote more efficient generation markets, we reject proposals to allocate to monopoly functions any costs associated with services that are or will be subject to competition. Specifically, we will not permit allocations of generation cost to distribution customers. To do so would compromise market efficiency by producing artificially low utility generation rates (or utility profits which do not correspond to utility risk) and provide competitive advantages, which would stifle competition to the utilities. Moreover, any allocation to monopoly customers of costs associated with competitive products would be unfair to monopoly customers because they would, in effect, be required to subsidize shareholder profits.

C. Utility Revenue Requirements Will Not Be Modified In This Proceeding.

Some parties propose that the Commission modify certain revenue requirements to reflect activities that the utilities will no longer undertake following the implementation of direct access. Utilities reply that this proceeding is not designed to accomplish any adjustments to their revenue requirements. They observe that AB 1890 does not direct the Commission to modify the utilities' revenue requirements here.

This proceeding is not the appropriate forum for reaching the potentially complex issues relating to changes in revenue requirements. In D.96-10-074, we ordered the utilities to file revenue requirements "based on our <u>last</u> <u>authorization</u> and separate this total between transmission and distribution" (emphasis added). By this, we stated our intent to consider existing utility revenue requirements in this proceeding. We have accordingly emphasized allocations of existing costs to utility functions in this proceeding rather than seeking to accomplish the more ambitious task of reviewing revenue requirements.

We are aware that the utilities' activities will change in the next few years. For example, the ISO will take on dispatch and management of electric loads. The utilities may eliminate or redefine some of their customer relations and generation activities. Even if we do not create new forums to consider these potential cost reductions, we recognize that these types of changes in activities will affect utility revenue requirements in the near future. We find nothing in AB 1890 to restrict this Commission's authority to adjust revenue requirements as long as the changes are otherwise consistent with the statute's provisions. In fact, AB 1890 requires PG&E to file a general rate case in late 1997. Edison's PBR review is scheduled for 1999. The Commission is in the process of mid-term reviewing of SDG&E's base rate PBR mechanism and may decide to review SDG&E's revenue requirement in the near future.

Until then, we are not inclined to consider changes in revenue requirement piecemeal because that it would be unfair to consider a few accounts in isolation. One way or another, utility rates will reflect lower costs, consistent with our and the Legislature's policy the purpose of electric restructuring is to exploit economic efficiencies and reduce electric rates. We therefore decline any proposals to change the size of the utilities' total revenue requirements here except where required by law.

D. Utility Risk Will Not Change In This Proceeding

The Commission's policy and AB 1890 set forth industry and regulatory changes that will in some instances create new risks for the utilities and in others shelter them from risk. Predictably, parties have advocated positions in this proceeding which would limit the liability of their respective constituencies. As always, our objective is to balance utility risk with opportunities for earnings in each relevant market. In this decision, however, we avoid having to weigh risk and reward to the extent possible. It is our intention to retain existing levels of risk overall. In so doing, we decline proposals which change the mix of risk and reward from that anticipated by AB 1890 and relevant Commission decisions.

We recognize that some of these principles may conflict or compete when applied to specific proposals. In such cases, we consider the relevant risks and costs, the primacy of our goal to promote competition, and principles of fairness. We address them where applicable to individual proposals in subsequent sections.

We proceed to address unbundling by first reviewing utility proposals generally. We then address allocations to specific functions or accounts within them and consider how to allocate costs between transmission and distribution revenue requirements. We then proceed to allocate revenues within each function and to establish rate design principles. Finally, we address billing and master metering issues.

V. Utility Revenue Requirements Proposals

The utilities each filed proposals for determining revenue requirements for each functional category: distribution, transmission, public purpose programs, and nuclear decommissioning and generation. In general, their proposals were very similar. Each would develop its competition transition charge (CTC) residually after determining other costs. They propose that the Commission adopt distribution revenue requirements by subtracting from nongeneration revenue requirements the transmission revenue requirements approved by the FERC. Each utility would allocate to distribution revenue requirement costs that they do not attribute directly to other functional categories.

AB 1890 requires the establishment of a separate rate component to collect the revenues to fund (1) energy efficiency activities; (2) research and development; (3) operation and development of renewable resource technologies; (4) low income energy efficiency services (LIEE), and (5) the California Alternative Rate for Energy (CARE) program.

AB 1890 also requires the establishment of a separate charge for nuclear decommissioning, which the utilities propose here.

Each proposal is discussed in more depth below.

A. PG&E

PG&E proposes the following 1998 revenue requirements for each functional category:

Generation	$5,222 million
Transmission	291
Distribution	2,031
Public Purpose Programs	270

PG&E derives the total by adjusting the revenue requirement adopted in its last general rate case consistent with its 1997 Energy Cost Adjustment Clause (ECAC) decision (D.96-12-080). It then increases the revenue requirements for its safety and reliability programs by an inflation factor plus two percent, or $172 million, pursuant to Section 368(e). PG&E also increases revenue requirements by $48 million to fund renewable resource technologies, consistent with Section 381(c).

PG&E states it assigned costs to various functions according to cost causation, consistent with Commission policy. Costs which it could not attribute directly to a function were allocated to distribution in most cases.

B. Edison

Edison propose' the following 1996 revenue requirement for each functional category:

Transmiss' n	$ 211 million
Distrib' on	1,816
Public Purpose Programs	178
Nucl ar Decommissioning	104

To derive the generation rate, Edison proposes to subtract from the rate levels in effect on June 10, 1996, the adopted PBR distribution rates, transmission rates, public benefits charges, nuclear decommissioning charges, rate reduction bond repayment charges and other miscellaneous costs. From this, Edison would determine the CTC residually by subtracting its cost of procuring energy and other services from the ISO/PX.

Edison recommends that the Commission derive its distribution rates by subtracting FERC-adopted transmission rates from the amount identified in its PBR as nongeneration rates. Edison refers to this residual approach to allocating costs as a "rate credit" method. Edison supports this approach by observing that the Commission has already approved Edison's nongeneration revenue requirement and that FERC is expected to rule soon on the utilities' transmission revenue requirement proposals.

Edison proposes to allocate administrative and general (A&G) costs between functions by identifying them in one of three ways: direct, joint or common. Direct costs are those that can be associated with a single business segment and are assigned to that segment. Joint costs are those which are associated with multiple business segments on the basis of an indirect relationship or pursuant to a special study of the costs. Common costs includes those that have no causal relationship to a single business segment or group of segments. Edison refers to common costs as fixed costs because they do not vary with specific factors. Edison observes that less than five percent of its costs are fixed.

In light of its understanding that FERC will not establish a final transmission revenue requirement in time for the introduction of direct access on January 1, 1998, Edison proposes a balancing account to adjust transmission and distribution revenues at a later time.

Edison proposes a balancing account and associated nonbypassable surcharge it titles the Miscellaneous Adjustment Mechanism (MAM) that would recover numerous generation-related costs, proposing an initial revenue requirement for the account of negative $22.244 million in 1998.

C. SDG&E

Like Edison and PG&E, SDG&E proposes to establish the distribution revenue requirement residually by subtracting the FERC-approved transmission revenue requirement from the nongeneration revenue requirement. To derive its current total revenue requirement, SDG&E used its last general rate case revenue requirement as the base, and escalated it for operation and maintenance (O&M) and capital costs using its approved PBR mechanism. It increased the amount to include authorized transmission O&M expenses approved in its 1996 ECAC decision. SDG&E also included two rate increases associated with the Fuel Price Index Mechanism authorized by Section 397 of AB 1890.

SDG&E's total revenue requirement by function is:

Transmission	$ 121 million
Distribution	542
Public Purpose Programs	
DSM	32
RD&D	4
Renewables	12
CARE	8.5
Nuclear Decommissioning	22

SDG&E assumed a revenue requirement of $73 million for repaying the bonds issued to reduce residential and small commercial rates.

VI. Development of the Distribution Revenue Requirements and Treatment of FERC Revenue Requirements for Transmission

The utilities propose that the Commission establish the distribution revenue requirements after subtracting the FERC-approved transmission revenue requirements from the combined non-generation revenue requirements. They observe that if the Commission does not account for the FERC revenue requirements, the utilities will either be denied an opportunity to recover reasonable costs or will have an opportunity to receive windfall profits from the difference.

Edison refers to its proposal as a "rate credit" approach. It argues that any other method would effectively require the Commission to relitigate its general rate case. SDG&E argues that deriving the revenue requirements using methods other than the one it proposes will create new risks for the utilities because the utility will not have an opportunity to recover its costs.

Farm Bureau argues that the utilities' method would permit the utilities to charge distribution customers for services not being performed. Edison responds that all of its distribution customers are also its transmission customers. It observes that a higher revenue requirement for one function implies a lower revenue requirement for the other, making the customer indifferent.

Several parties, including CAC/EPUC, CLECA/CMA, CIU, ORA, and TURN/UCAN, argue that the utilities' approach would require the Commission to abrogate its authority to the FERC by effectively allowing the FERC to determine the utilities' distribution revenue requirements. Edison responds to this concern by observing that the Commission found the total nongeneration revenue requirement to be reasonable and that it may be assured that the FERC transmission revenue requirement will be reasonable. The difference between the two, therefore, must also be reasonable, according to Edison.

CAC/EPUC also argue that under Edison's rate credit approach, Edison will have an incentive to stipulate to any level of transmission revenue requirement, and its allocation between the wholesale and retail jurisdictions. Edison responds that because it has to update its Transmission Revenue Requirements at FERC annually, it will have every incentive to "get it right" from the outset.

CIU recommends that the Commission assume for ratemaking purposes that the FERC has adopted the revenue requirements the utilities proposed, rather than the one the FERC ultimately adopts. The utilities reply that this approach would almost certainly result in revenue losses for them.

CLECA/CMA observe that FERC may adopt a revenue requirement that differs from previous Commission revenue requirements for transmission because it may, for example, employ a different rate of return or different depreciation rates. The resulting lower revenue requirement, according to CLECA/CMA, should not be made up by distribution customers whose rates are subject to Commission jurisdiction. Edison responds that such differences may be monitored by the Commission and accounted for.

One of the consequences of electric industry restructuring is the transfer of transmission ratemaking activity from the Commission to FERC. Although FERC always retained authority over regulation of transmission, it deferred to the states to set a total revenue requirement for the transmitting utility, a revenue requirement which included the reasonable cost of transmission. Henceforth, FERC will have sole responsibility to set transmission revenue requirements.

We defer to FERC's authority and its decisions. Nevertheless, we will not abandon our own authority or responsibility to FERC by allowing it to determine the revenue requirements for distribution, a determination over which we have sole responsibility and authority, which no party disputes. To be sure, we may not lawfully delegate our authority to another agency. Section 454 requires the Commission to issue findings with regard to the reasonableness of utility rates, a process which assumes cost allocations between customer classes and utility functions. AB 1890 requires a rate freeze and a "fire wall" which retains certain cost allocations between customer classes. It nevertheless provides in Section 367(e)(3) that "The Commission shall retain existing cost allocation authority, provided the fire wall and rate freeze principles are not violated." Establishing a distribution cost allocation which is premised entirely on the findings of FERC would be an abrogation of our authority under Section 454 and Section 367(e)(3).

If, as the utilities argue, the potentially disparate ratemaking decisions of FERC and this Commission creates risk, it is a risk already anticipated by AB 1890 and previous Commission decisions. Accordingly, regulation and legislation have already accounted for this risk in offsetting concessions to the utilities. In any event, the risk that the FERC and Commission decisions may create a shortfall is at least partially offset by the opportunity for additional profit, as PG&E observes.

We also reject the utilities' proposals to set distribution rates residually because it could put us in the position of second-guessing FERC decisions. To the extent that FERC reduces the utilities' proposed revenue requirements, it finds that for whatever reason the costs of utility transmission are not reasonable. The utilities propose that we effectively overlook the FERC's findings and to determine that those same costs are reasonable by including them in distribution rates. We would only grant such a request with a showing that the specific costs are both reasonable and associated with distribution activities. None of the utilities have made such a showing here if for no other reason than they have no FERC decision upon which to form their proposals.

Just as we have declined to reduce the distribution revenue requirements in this proceeding to account for costs associated with activities the utilities may no longer conduct, we decline to increase the distribution revenue requirements to account for FERC decisions. In each instance, the utilities will have an opportunity to make their case with regard to specific revenue requirements changes in their PBR proceedings or, for PG&E, general rate case. In the interim, we will adopt the revenue requirement for distribution that each utility proposes here with the adjustments we make in subsequent sections, consistent with law and policy. To the extent necessary, we will revisit these revenue requirements at a later date, as discussed below.

VII. Functional Accounts

A. Load Dispatching and Costs Associated with the PX and ISO.

The utilities have historically incurred costs in dispatching power to customers on their systems and managing those dispatching activities to provide high-quality service. With the introduction of direct access, the ISO and PX will take on these activities.

TURN and UCAN argue that the utilities have inappropriately included in their distribution revenue requirements the costs of load dispatching and power purchasing. TURN and UCAN observe that the ISO and PX will be assuming related responsibilities and that the utilities should not be able to include such costs in rates. TURN and UCAN recommend reducing PG&E's revenue requirement by $10.83 million, SDG&E's by $5.53 million and Edison's by $17.02 million for associated costs. ORA objects to SDG&E's allocating these load dispatching costs in its generation function to the distribution function because this results in asking SDG&E's regulated business to subsidize its competitive services.

Edison comments that the Commission should not reduce these revenues because the proposal ignores the fact that the utilities will incur additional implementation costs. SDG&E will incur costs associated with "interface" activities with the ISO.

One of our criteria for determining the reasonableness of a proposal is whether it allocates the costs of a given function to that function's revenue requirement. Here, the utilities propose to include in the distribution revenue requirement the costs of generation dispatch and control. The utilities will no longer conduct generation dispatch and control beginning January 1, 1998. While there may be some uncertainty about the ongoing activities the utilities will conduct in working with the ISO, we are not convinced that the utilities' activities will differ in any significant respect from those of its generation competitors. Therefore, the dispatch and control "interface" and "implementation" costs will be the responsibility of the ISO and will be included in ISO transmission rates. We therefore follow TURN and UCAN's recommendations to remove associated costs from the utilities' revenue requirements for distribution. Assuming these costs should be allocated to transmission, PG&E had already removed the associated $10.83 million from its distribution revenue requirement which therefore requires no further adjustment. Edison makes a reasonable argument in its comments that some load dispatching activities will remain with it after January 1, 1998. Edison did not , however, make an affirmative showing to support allocating the entire load dispatching revenue requirement to distribution. We therefore remove from Edison's distribution revenue requirement an amount equal to that amount PG&E removes from distribution revenue requirement, $10.83 million. We remove $5.5 million from SDG&E's distribution revenue requirement the amount of these costs that it included in its March 31 FERC transmission revenue requirement. If FERC concludes that these load dispatch and ISO/PX related costs are distribution costs, rather than transmission costs, then we will reallocate these costs to distribution, consistent with FERC's findings.

B. Line Extension Allowances

TURN/UCAN propose that the Commission in this proceeding recognize the changes to line extension policy which may be adopted in R.92-03-050. Specifically, they believe line extension allowances should be scaled back to reflect only the distribution revenues, rather than total revenues reflected in current allowances. They also believe changes in line extension allowances should be reflected in revenue requirements adopted here.

ORA and the utilities agree that the Commission should defer this issue to R.92-03-050 the rulemaking associated with this issue. CBIA objects to TURN/UCAN's proposal, arguing that the Commission does not have adequate evidence in this proceeding to revise existing rules.

We agree that we do not have adequate information here to undertake any changes to line extension rules or the way rates are designed to accommodate rule changes. We will defer consideration of this issue to R.92-03-050 and revisit the issue as it affects revenue requirements in the utilities' PBR and general rate cases, if necessary.

C. Cost of Capital

SDG&E recommends retaining a bundled cost of capital and not unbundling it by functions. It observes that as an integrated company, it does not have separate units issuing their own debt and equity. PG&E and Edison also assume the cost of capital would not change in this proceeding.

TURN and UCAN propose that the Commission initiate a proceeding to develop and implement unbundled costs of capital that will reflect the risks associated with unbundled utility functions. They believe the Commission should make 1998 rates subject to refund for this purpose. TURN and UCAN observe that the Commission earlier declined to unbundle the costs of capital in 1994 because it believed the exercise was premature, suggesting the issue would be reconsidered as rates were unbundled (D.94-11-076).

Edison generally concurs with TURN and UCAN's procedural recommendation, although it does not agree with their assumption that rates of return are likely to fall.

We agree that the utilities' authorized cost of capital should ultimately reflect new market structures and the variation in risk between various utility functions. We do not believe the need for such a review, however, is urgent. Edison and SDG&E were excused from comprehensive cost of capital reviews in their PBRs. We will consider unbundling utility cost of capital in the generic cost of capital review proceedings as proposed by PG&E and SDG&E in their comments on the proposed decision and will direct the utilities to file applications on May 8, 1998.

D. *Escalation Factors*

In developing this 1998 revenue requirements, the utilities "escalated" their last authorized revenue requirement to account for the effects of inflation on their costs. SDG&E escalated its revenue requirement for transmission and distribution by using the method adopted by the Commission in its PBR for SDG&E's total revenue requirement.

ORA opposes SDG&E's escalation methodology on the basis that the mechanism was designed to address the effects of escalation on the combined company. ORA observes that the results provide estimates of transmission and distribution compared to generation that are out of line with actual ratios. ORA proposes instead to determine the percentage of the transmission and distribution revenue requirements compared to the total 1993 revenue requirement and then applying that percentage to the 1996 authorized base revenue requirement.

SDG&E's method applies most recently adopted PBR escalation rates and is generally reasonable. We therefore adopt it. However, the record shows that SDG&E used the PBR escalation rates only through 1996. In its opening brief and Exhibit 10, SDG&E stated that it will file updates for the transmission and distribution revenue requirements to reflect the authorized 1997 and proposed 1998 PBR escalation rates later this year. Therefore, we will reflect these adjustments to the authorized distribution revenue requirement effective January 1, 1998 in an advice letter filing SDG&E shall file no later than October 15, 1997.

PG&E's escalation factor of CPI plus 2% for transmission and distribution revenues and Edison's non-generation escalation factor as adopted in D.96-09-092 were not controversial, and we adopt them.

E. Catastrophic Events Memorandum Accounts (CEMA)

Edison, PG&E, and SDG&E currently have CEMAs into which they enter costs incurred during catastrophic events. ORA proposes that Commission eliminate the CEMA for generation costs on the basis that it would provide a competitive advantage to utilities. Edison and PG&E's proposals are consistent with this recommendation. SDG&E's distribution revenue requirement appears to have no CEMA costs included in it. We adopt the proposals to eliminate CEMA for generation-related costs for all three utilities, effective January 1, 1998.

F. Hazardous Substance Clean-up and Litigation Cost Accounts (HSCLS)

Edison, PG&E, and SDG&E currently have HSCLSs into which they enter costs associated with hazardous waste clean-up. ORA recommends that these accounts no longer include the costs of generation-related clean-up. Retaining these accounts for generation-related costs would provide a competitive advantage to the incumbent utilities. We adopt ORA's proposal to prohibit entries into HSCLS which relate to generation costs, effective January 1, 1998. The resulting adjustment to distribution revenue requirements for Edison is $1.36 million and for PG&E is $.1 million. SDG&E did not include an HSCLS balance in its distribution revenue requirement. Therefore, that revenue requirement needs no associated adjustment.

G. Administrative and General (A&G) Expenses

1. Fixed A&G Costs

Edison proposes to allocate to distribution revenue requirement the fixed A&G costs associated with fossil generation. These costs, Edison observes, are those that could otherwise be assigned to generation by way of a multi-factor allocation method. Edison believes intervenors' recommendation to allocate these fixed costs to generation by way of the multi-factor approach would represent "an improper disallowance of appropriately incurred costs" because they are costs Edison cannot recover in competitive generation markets. It argues that these fixed costs would be incurred whether or not it divests its generation assets and that at least some costs are fixed over a period of time. Since they are reasonably incurred, Edison argues, they must be recoverable in rates.

SDG&E and PG&E also allocated A&G costs to distribution which they could not attribute directly to other functions, changing existing allocations to transmission and distribution. PG&E believes it will not avoid such costs if it divests itself of generation. It argues that allocating residual costs to generation would require PG&E to set generation prices that would not be sustainable in competitive markets. PG&E and SDG&E argue that the assignment of only incremental costs to generation is efficient and does not create competitive advantages because competitors will compete based on their incremental costs.

CAC/EPUC and Farm Bureau object to the utilities' exclusion of A&G costs from generation accounts. CAC/EPUC observe that PG&E's justification for its method is unsupported by AB 1890 which requires all "going forward " A&G costs to be included in the generation revenue requirement. AB 1890, according CAC/EPUC, does not refer to "incremental" costs or otherwise distinguish fixed costs in ways which would support the utilities' reliance on AB 1890.

Enron also believes PG&E has shifted A&G costs from generation to distribution based on past allocations used to set FERC jurisdictional rates. CLECA/CMA argue the utilities should not be permitted to use an incremental approach when it suits their interests, as here, and an embedded one when it doesn't. CLECA/CMA take issue with the utilities' position that their distribution fixed costs won't change after their assets are divided in half. CLECA/CMA also observe that the utilities' approach is anticompetitive because competing firms must ultimately recover all of their costs, not just those that are incremental, from the market.

ORA believes the utilities' approach applies incremental ratemaking in an exercise that involves embedded costs. It believes the utilities will be able to recover their fixed generation costs readily in the marketplace for generation.

DOD rejects the utilities' argument that their proposals are consistent with the Commission's pricing of telecommunications costs based on "TSLRIC" (total service long-run incremental costs). DOD observes that the Commission has specifically required that TSLRIC include all cost components and that the Commission set TSLRIC without regard to embedded revenue requirements. DOD would propose going forward on that basis, believing that the utilities' corresponding rates would be considerably lower as a result.

TURN and UCAN propose phasing out generation fixed costs at a rate of 25% annually to recognize that fixed costs are variable over time, that is, they may be reduced according to output.

Edison argues that TURN and UCAN have improperly considered cost reductions already reflected in Edison's cost studies. It believes UCAN and TURN's phase-out proposal is unsupported by any study of Edison's actual costs.

<u>Discussion</u>: Some utility costs do not vary over some period of time. They are incurred notwithstanding the utility's output. It does not necessarily follow, however, that distribution customers should assume liability for all such costs even if the utilities will continue to incur them. The utilities' argument that they will be unable to recover these costs in generation markets is not convincing. Their competitors also incur fixed costs. Arguably, competitors' fixed costs are higher per unit of output than the utilities' because many competitors will not realize the economies of scale or scope which the utilities enjoy. A utility's generation system, whether it is owned and operated by the utility or any other entity, will continue to incur fixed costs which must be allocated to generation. Moreover, uneconomic generation costs are to be recovered in the CTC, pursuant to AB 1890, not in distribution rates.

Section 367(c) of AB 1890 requires that all "going forward costs" of fossil plant operation must be recovered "solely from independent Power Exchange Revenues or from contracts with the Independent System Operator." We are unaware of any definition that limits "going forward costs" to incremental costs. In this regard, PG&E's application of economic theory – that its competitors will decide whether to produce an incremental unit on the basis of their incremental costs – is only part of the story. Over time, all generation firms must recover all costs, including those types of costs which the utilities seek to allocate solely to distribution. Consequently, allocating to distribution customers all fixed costs would create a competitive advantage to the utilities at the expense of captive ratepayers, contrary to our stated objectives and the requirements of AB 1890.

We do not agree that allocating generation fixed costs to the generation component of a utility's revenue requirement will result in an effective disallowance of reasonable costs. If the utilities retain generation facilities, they may recover fixed costs in energy revenues. Fixed A&G costs may also be recoverable as part of "must-run" contracts with the ISO. Both Edison and PG&E plan to sell substantial portions of their generation systems. However, it is important to remember that each utility will retain some portion of its generation assets for which they should pay a fair share of the common A&G costs at issue here.

If they sell generation facilities, the utilities will have opportunities to reduce their overheads. In addition, the utilities may be able to recover fixed A&G as part of the two-year service contract between utilities and purchasers of generation plant required under Section 363.

The utilities have not demonstrated that every type of fixed cost cannot be reduced, that is, made variable, over the medium term by changes in procurement practices (for example, by contracting out payroll processing) or by offering a related service to other businesses (for example, by selling advertising space in bill envelopes) or by reducing employees (for example, by reducing legal employees to recognize reduced regulatory and legal activities). In effect, the utilities argue that substantial economies of scale exist in their vertically integrated operations, a reasonable assumption. To the extent that it is true, we have no doubt that the utilities and their competitors will take advantage of them with a great deal of inventiveness. As CAC/EPUC observe, however, it is impossible to determine at this time how A&G

expenses will change in a competitive market or when the utilities divest their generation.

However, we are persuaded that some of these fixed A&G costs may remain following divestiture and the end of the period during which the utility operates the plant on behalf of a purchaser. On the other hand, we want the utilities to take actions to reduce their costs, especially as a result of divestiture.

It is not our intent to deny utilities an opportunity to recover reasonable costs which they actually must incur, but we must balance this with our need to ensure that ratepayers are not paying for costs that no longer exist. To the extent that the fixed A&G costs we have allocated to generation are truly fixed and continue to exist following this period, we will review and reallocate continuing fixed A&G costs to distribution using a streamlined procedure. No such procedure was proposed in this proceeding. The Assigned Commissioners in this proceeding shall develop a streamlined process for this reallocation by December 16, 1997.

Consistent with the principles we have articulated earlier in this decision, we will not allocate to distribution functions the costs associated with other functions at this time. The utilities have presented no compelling reason to stray from this principle in the case of A&G costs. We therefore reduce the utilities' proposed distribution revenue requirements as follows:

Edison	$25.15 million
PG&E	$49 million
SDG&E	$ 4.90 million

These amounts are calculated on the basis of multi-factor allocation methods provided by each utility pursuant to ORA's recommendation.

2. SONGS and Palo Verde A&G Costs

Edison proposes that all A&G costs related to the San Onofre Nuclear Generating Station (SONGS) and Palo Verde Nuclear Generating Station which were not included in the Incremental Cost Incentive Procedure (ICIP) in the related settlement decision (see D.96-04-059) should be included in Edison's distribution revenue requirement. The SONGS settlement agreement is in effect through 2003, past the end of the rate freeze period. The Palo Verde settlement ends at the end of 2001. In each of these settlements, a portion of nuclear A&G costs were not included in ICIP or sunk costs. We reject the approach proposed by Edison to include these costs in distribution for the same reason we have declined to include other types of generation costs in distribution rates. Instead, we direct Edison and SDG&E to file a petition to modify relevant Commission decisions in order to include these A&G costs in ICIP because we believe that these costs are appropriately part of ICIP. To the extent that there are above market ICIP costs, they may be appropriately included in transition costs. That is a matter for resolution in A.96-08-001 et al. We therefore reduce Edison's proposed distribution revenue requirement by $24.51 million.

3. Customer Services and Marketing Costs

Edison would allocate to distribution about $23 million for customer service and marketing costs for its large customers. It believes these costs should be included in distribution rates because, consistent with FERC accounting guidelines, they are incurred to educate customers about electric system health and safety, conservation and economic use of electricity. SDG&E would allocate $5 million to distribution for marketing costs, stating that it refers to the associated activity as "marketing" consistent with the FERC's system of accounts.

PG&E seeks $15.1 million for marketing costs.

TURN and UCAN propose to remove from revenue requirements all marketing costs associated with positioning the utilities in competitive markets. They would allocate such costs, including overhead costs, to generation customers. They observe that the Commission has removed such "brokering" costs from gas rates, costs which are comparable to those referred to here as "marketing." They also present substantially higher estimates of these costs than those presented by the utilities.

Edison replies that TURN and UCAN have improperly characterized these costs as marketing costs. Edison states it will not be marketing generation with associated funds and observes that it will continue to incur expenses relating to customer service research, bypass options, rate design and customer education. Edison also objects to TURN/UCAN's "arbitrary" assignment of $12.7 million in common plant and overheads to marketing and customer service expenses. SDG&E responds similarly, arguing that large customers are entitled to receive a high level of customer service during this period of dramatic change.

With the introduction of direct access, utility distribution customers will continue to require a high level of customer service with attendant funding requirements. The matter for resolution here, however, is whether and the extent to which the cost of that service is appropriately assigned to distribution revenue requirements. We share TURN/UCAN's concern that the utilities have allocated more than a fair share of customer service and marketing costs to distribution. Some of the activities the utilities support with that funding are not related to the distribution system, such as providing information regarding bypass options. Most of the activities arguably fall in all three major functional categories, including research and providing information about company policy, procedures, rate design and billing.

We therefore reduce the utilities' distribution revenue requirements to reflect customer service and marketing costs that are more appropriately allocated to generation. TURN's estimates appear to assume that all customer service and marketing costs are related to generation. The utilities make reasonable arguments that some of those costs will continue to be incurred notwithstanding the status of their generation operations. Reviewing their general rate cases, we agree that some of the costs in related accounts will be associated with each utility's distribution operations. Because the utilities did not fulfill their burden to specify the costs which might be attributable to distribution, we adjust the amounts for Edison and SDG&E by applying their respective multifactor allocations methods. This results in an adjustment of $7.7 million for Edison and $.98 million for SDG&E. In its comments, Edison alleges that allocating a portion of economic development costs to generation would be "contrary to law" because we identified such costs as "nongeneration" in Edison's PBR order, D.96-09-092. Edison fails to acknowledge, however, that D.96-09-092 allocated all other customer services costs to generation. Our decision here to allocate all customer services costs, including those associated with economic development, across all functions therefore gives Edison the benefit of the doubt. For PG&E we make no adjustment because we removed marketing costs from PG&E's revenue requirement in its most recent general rate case. We therefore do not adjust PG&E's distribution revenue requirement here for this item.

H. Franchise Fees and Uncollectibles (FF&U)

Franchise fees are payments made to local governments for the privilege of constructing distribution and transmission facilities in local communities and are based on total revenues. Uncollectibles are those losses associated with customers who fail to pay their electric bills. SDG&E and Edison propose to allocate related costs to distribution and transmission.

ORA proposes that SDG&E and Edison be required to allocate some portion of FF&U to generation, consistent with PG&E's method. If revenues are reduced as a result of divestiture of generation, FF&U should be reduced accordingly. Therefore, we agree with ORA's proposal and PG&E's methodology and allocate to generation one-third of FF&U costs. This results in an adjustment of $7.47 million in Edison's distribution revenue requirement and $ 6.4 million in SDG&E's distribution revenue requirement.

I. Miscellaneous Revenue

TURN/UCAN propose that SDG&E be required to update its "miscellaneous revenue" category, which SDG&E shows as $15 million in this proceeding and which TURN believes the Commission increased in D.95-04-048.

D.95-04-048 adopted a number of changes to increase the miscellaneous revenues. Contrary to TURN's assumption, however, the changes are credited to SDG&E's Electric Revenue Adjustment Mechanism (ERAM) balancing account. We therefore reject TURN's recommendation.

J. Accounts and Charges for Potentially Uneconomic Costs

All three utilities propose to create additional balancing accounts with associated "nonbypassable surcharges" to customer bills for costs which they believe are uneconomic and deserving of special consideration.

1. PG&E's Diablo Canyon ICIP Account

PG&E proposes to create the nonbypassable charge to recover Diablo Canyon nuclear power plant Incremental Cost Incentive Pricing (ICIP) prices that exceed market prices. PG&E states it is authorized to recover such costs because its cost recovery plan, approved by the Commission, provides that these costs would be recovered through a special mechanism rather than through the CTC.

ORA opposes the account on the basis that generation costs should not be recovered from distribution customers. TURN/UCAN oppose the account arguing that the charge is effectively another CTC except in name. TURN/UCAN believe the above-market ICIP may not be collected as CTC. They also believe the issue is appropriately the subject of Phase 2 of the CTC proceeding.

2. Edison's MAM

Edison proposes to create a MAM, a balancing account that would serve as the vehicle for recovery of certain costs related to generation, distribution, public purpose programs, and other functions. Costs entered into the account would be recovered by way of a nonbypassable charge on customer bills, which Edison refers to as the Miscellaneous Adjustment Mechanism Billing Factor (MAMBF). Edison's MAM would initially be a surcredit or rate reduction of $22.24 million.

Edison includes in the MAM revenues and costs associated with non-utility affiliates, costs associated with nuclear spent fuel storage and Department of Energy fees, low emission vehicles and hazardous waste costs, SONGS 1 shutdown O&M expenses and the gain on the Yuma-Axis settlement. It would also include intervenor funding, and the Reduced Cost Recovery Amount (RCRA), Devers-Palo Verde regulatory costs, past earthquake recovery costs (and other costs entered into the CEMA) and the costs of its fuel oil pipeline. In all, Edison proposes to include the costs associated with 39 different activities into the MAM. Edison argues that none of these costs are readily assigned to functional business segments. Because the Commission has found the costs to be reasonable, Edison believes it should be granted dollar-for-dollar recovery of them by way of a nonbypassable charge.

ORA opposes the MAM on the basis that the MAM would permit Edison to recover through distribution charge costs that are related to generation, including SONGS 1 shutdown O&M, hydroelectric pumped storage costs. ORA argues that this balancing account, like others proposed by the utility, is proposed in the name of "guaranteed cost recovery which derails the allocation process."

CLECA/CMA argue that the MAM circumvents the Commission's objectives in assigning costs to utility functions and violates the spirit of AB 1890 by ignoring the requirement that rates remain frozen. CLECA/CMA believe the utility proposals are offered with the objective of reducing risk beyond that anticipated by AB 1890 and the Commission's policy.

TURN/UCAN oppose the MAM, arguing that it includes costs that should not be assigned to distribution customers. They oppose the MAM for the same reason they oppose the Diablo Canyon ICIP charge, namely, that the MAM is a CTC except in name and except in the fact that Edison proposes that the MAM continue after the CTC is eliminated in 2002. TURN and UCAN argue that AB 1890 did not permit a balancing account to recover these costs and that the costs are not distinguishable from any other electric base revenue requirement.

3. SDG&E's MAM

SDG&E also proposes to recover $14.26 million in a MAM account which, like Edison's MAM, would be charged to distribution customers. SDG&E's MAM would include four cost components, among them the SONGS I shutdown costs, spent nuclear fuel storage costs, Department of Energy (DOE) decontamination and decommissioning costs and SONGS 2&3 costs not recovered by the ICIP pricing mechanism.

SDG&E supports its request by arguing that the Commission has already authorized recovery of these costs. It observes that it may not be able to recover the costs during the period over which the CTC will be in effect. Its MAM, like Edison's, would be in effect after the CTC is phased out.

TURN/UCAN and ORA oppose SDG&E's MAM on the same bases they object to Edison's MAM. ORA observes that SDG&E's witness on the subject suggested that these costs can be treated as transition costs. TURN and UCAN argue that the SONGS ICIP costs are appropriately part of SDG&E's base rate revenue requirement and should not be shielded from risk as part of a nonbypassable charge.

4. Discussion

We have stated that one criteria for evaluating parties' proposals here is whether costs are allocated to the function with which they are associated. Many of the costs in these various accounts are related to generation, public purpose programs, or transmission. The utilities nevertheless propose to allocate the costs to distribution, contrary to our stated policy.

We have also stated our intent to retain existing levels of risk in this proceeding. As the utilities admit, these three accounts are designed to reduce utility risk by guaranteeing recovery of certain costs, some of which are currently recovered under different types of ratemaking mechanisms. The nonbypassable surcharges and associated balancing accounts change the mix of risk the utilities face pursuant to Commission orders and AB 1890, contrary to our stated policy.

The utilities justify including these costs in these accounts on the basis that they have already been approved by the Commission. Our past approval of the reasonableness of these costs, however, does not distinguish them from other costs included in other rates or ratemaking mechanisms. The costs recovered through the CTC and in distribution rates, for example, have already been approved in general rate cases. Whether a utility is required to recover, for example, SONGS O&M costs in generation rates or in a MAM account implies nothing about the reasonableness or unreasonableness of those costs. It merely reflects degree of risk which we believe is appropriate for cost recovery and consistent with AB 1890.

In considering the validity of the proposed surcharges, we consult AB 1890. The statute sets forth a complex and comprehensive regulatory framework for restructuring the electric industry. As part of that framework, it mandates the creation of the CTC, a nonbypassable charge, the purpose of which is to provide the utilities with a reasonable opportunity to recover generation costs that might otherwise become stranded in the new market framework. Specifically, Section 367 identifies the regulatory treatment for various types of costs and finds that "uneconomic costs shall be recovered from all customers on a nonbypassable basis" and be amortized over a period which "shall not extend beyond December 31, 2001," with specified exceptions.

The utilities' proposals here seek authority to impose nonbypassable charges for generation costs which are not authorized by AB 1890. The utilities characterize as potentially "uneconomic" the costs that would be recovered by the charges. The costs are not listed as exceptions to the general provision that uneconomic generation costs are to be recovered through the CTC and amortized prior to December 31, 2001. In addition, the utilities would retain the proposed surcharges after December 31, 2001, providing a regulatory protection which extends beyond the period anticipated by AB 1890 for recovery of stranded generation costs.

As a matter of policy, we question the fairness of transferring risk to captive customers. As a matter of law, the rule of statutory construction provides that "'where exceptions to a general rule are specified by statute, other exceptions are not to be implied or presumed." (Mutual Life Insurance Co. v. City of Los Angeles, 50 Cal.3d 402, 410 (1990).) The costs which the utilities would include in additional balancing accounts or nonbypassable charges are in addition to the exceptions listed in AB 1890 for recovery by methods other than the CTC. To the extent they might be uneconomic generation costs, they must be recovered through the CTC.

The purpose of this proceeding is to unbundle revenue requirements, not to create new ratemaking mechanisms. Just as we have declined to reduce revenue requirements to reflect lower costs in this proceeding and to eliminate existing balancing accounts, we decline to consider new ratemaking mechanisms. Those ratemaking mechanisms are appropriately topics of other proceedings. We are especially concerned with Edison's proposal to remove from its PBR $20 million annually in costs related to its pipeline terminal company and to change the existing ratemaking incentive associated with nuclear performance to a mechanism which would guarantee recovery of $14.6 million in annual costs.

Finally, we comment specifically on PG&E's Diablo Canyon ICIP proposal. We observe that we have never authorized the creation of such a charge either implicitly or explicitly. PG&E's cost recovery plan did not propose such a surcharge,[7] although the plan stated PG&E would not recover associated costs through the CTC. In this proceeding, PG&E provides no legal authority for the charge or analysis to support its imposition. Even if we were to interpret AB 1890 to permit such additional nonbypassable surcharges on customer bills, we would reject this one on the basis that its proponent has failed to meet its burden to support it.

The issue remains as to where the costs of the various utility balancing accounts should be allocated. SDG&E's proposed MAM included only generation costs. They may be recoverable as part of the CTC or SDG&E's generation rates and require an associated Commission finding in R.94-04-031. Its proposed revenue requirement for distribution is not therefore not changed. Similarly, PG&E's regulated (that is, distribution and public program surcharge) revenue requirements do not change because the costs associated with Diablo Canyon which are not related to decommissioning would be ultimately allocated to generation costs or transition costs.

Edison's proposed MAM includes the costs associated with many activities which are attributable to several functions. TURN/UCAN, CLECA, Farm

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[7] We also clearly limit the scope of our approval of the cost recovery plans: "The [utilities' cost recovery] plans vary considerably in their level of detail. Our approval ... covers only the general framework for cost recovery outlined in AB 1890 and the details necessary to launch the program for cost recovery." (D.96-12-077, slip op. At 5.)

Bureau, and ORA propose specific treatment of each of the accounts' components. These parties agree with the appropriate treatment of most costs. Where they do not agree, we adopt ORA's proposals except with respect to the following costs. Costs associated with DOE D&D fees, SONGS 1 shutdown O&M, and spent nuclear fuel storage should be allocated to nuclear decommissioning. For SDG&E, these same costs should be allocated to nuclear decommissioning. As described in Section VII.F., hazardous substance clean-up and litigation cost accounts should no longer include generation related costs after January 1, 1998. The existing HSCLC balances that are generation-related have the characteristics of a regulatory asset. In addition, the Nuclear Unit Incentive Procedure account also has the characteristics of a regulatory asset. As such, disposition of these generation costs is appropriately considered in A.96-08-001 et al. With these modifications, Edison's distribution revenue requirement is reduced by $73.51 million. Its public program surcharge revenue requirement is increased by $7.113 million. Its nuclear decommissioning revenue requirement is increased by $19.4 million. Appendix B presents how the many types of costs would be allocated among transmission revenue requirement, distribution revenue requirement, generation, the CTC, the nuclear decommissioning surcharge or the public purpose program surcharge. As Edison points out in its comments, account balances allocated to the distribution revenue requirement are all one-time charges and not ongoing costs which would be included in the PBR indefinitely. They should be treated accordingly and would not be subject to the PBR escalation.

K. PG&E's TRA

PG&E proposes to replace the existing ECAC and ERAM balancing accounts with a "Transition Revenue Account"(TRA). In effect, the TRA is a balancing account for all costs except those subject to PX pricing and CTC treatment. The TRA would guarantee recovery of the authorized revenue requirements.

ORA opposes the TRA partly on the basis that it is the functional equivalent of the ERAM account. ORA observes the Commission has a separate process for evaluating ERAM and ECAC, which is part of the Electric Tariff Streamlining workshop, consistent with D.96-12-088.

We concur with ORA's observation that the TRA is not apparently distinguishable from PG&E's ERAM and that the topic is the subject of more comprehensive review in the Electric Tariff Streamlining effort. Moreover, we are not predisposed toward creating new balancing accounts in this proceeding in any event because to do so would compromise our objective of maintaining existing levels of risk, as we have stated.

L. *Final Revenue Requirements*

We adopt the following distribution revenue requirements for the utilities:

Edison	$1.67 billion
PG&E	$1.95 billion
SDG&E	$501.6 million[3]

TURN proposes that rates adopted in this proceeding be set subject to refund because the utility proposals were inadequate and require reconsideration at a later time. We do not believe, as the utilities argue, such an approach would necessarily represent retroactive ratemaking. On the other hand, we are not inclined to revisit these issues in 1998 because of resource constraints and because we wish to promote some certainty among industry participants, customers and parties to our proceedings on these matters. In reaching this conclusion we recognize that the utility revenue requirements are not ideal. Nevertheless, we believe they are adequate until we review utility revenue requirements in relevant PBR or general rate case proceedings.

VIII. Revenue Allocation and Rate Design

Having developed the revenue requirements for each utility, we proceed to determine revenue allocation to customer classes and rate design for various services. Unbundling requires this process of allocating revenues between customer classes in

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[3] To be updated to reflect the distribution portion of SDG&E's adopted 1997 and proposed 1998 PBR adjustments in SDG&E's advice letter filing by October 15, 1997.

order to get rates for each customer class. Rate design is required in order to determine the types of rates and services available to customers within a customer class.

As stated previously, AB 1890 limits total rates effective on January 1, 1998 to those shown on June 10, 1996 tariffs. The variations between the utilities' proposals are therefore limited. In general, the utilities propose to retain current unit rates with the exception of mandated reductions to residential and small commercial rates. The parties also appear to agree that the Commission will have to revisit revenue allocation and rate design issues prior to the end of the transition period in order to develop appropriate rates reflecting the removal of the CTC rate component and the associated revenues.

A. *Revenue Allocation*

1. Methods For Allocating Distribution Revenues

As we discussed under retail Transmission Rate Stipulations (Sec. III), we adopt ORA's recommendation to use Edison's EPMC approach on total revenues.

2. Allocation of the Rate Reduction Bond Recovery Costs and Discounts

AB 1890 requires that only those customers who receive the 10% rate reduction--residential and small commercial customers--pay off the costs of the associated rate reduction bonds, which will return the costs of the rate decrease to the utilities. SDG&E proposes that only those customers on its Schedule A be eligible for the discount. ORA proposes that time-of-use customers also receive the discount. SDG&E believes this practice would complicate the administration of AB 1890's requirements.

Notwithstanding any administrative difficulties which may result, AB 1890 requires that residential and small commercial customers receive the rate reduction. In so doing, it does not distinguish between time-of-use customers and others. We therefore require that the utilities offer the reduction to all residential and small commercial customers, including those who subscribe to time-of-use schedules.

3. Allocation of the Costs of Public Purpose Programs, CARE, Nuclear Decommissioning/Incremental Cost Incentive Price

Both the Commission and AB 1890 find that some programs should be funded by way of separate billing charges, among them CARE, public purpose programs such as energy conservation and research and development (R&D) efforts, and nuclear decommissioning costs.

PG&E proposes to allocate the costs of public purpose programs using the system average percent method whereby the CARE program costs are allocated first on an equal cents per kilowatt-hour (kWh) basis then, the remainder is allocated according to the percentage share of the schedule's present revenue requirements relative to the total present revenue requirements. PG&E states that this method is consistent with the current procedure for allocating such costs.

SDG&E and Edison propose instead to allocate these costs on the basis of equal cents per kWh during the rate freeze period. Edison believes using system average costs would be too complicated. SDG&E refers to its proposal as "easy to administer."

DOD, CIU, and CLECA/CMA oppose SDG&E and Edison's method for allocating public purpose program costs, believing they will shift costs to high load factor customers. CAC/EPUC takes the same position, arguing that Edison's allocation would violate the provision in AB 1890 that prohibits cost-shifting.

ORA believes direct access customers, utility full-service customers and bypass customers should pay the same amounts for these types of costs. Accordingly, ORA would calculate the charges as if all customers were served on bundled rates. This means direct access and bypass customers would pay proportionally more than full-service utility customers on the basis of their distribution costs.

We direct the utilities to allocate these program costs using PG&E's system average percent method, which is closest to current cost allocation methods and therefore accommodates AB 1890's rates freeze and prohibition against cost-shifting. Although the rate freeze eliminates any practical effect of this decision, we agree with

CIU and CLECA/CMA that the cost allocation principles we adopt today will as a practical matter serve as the foundation for future debates, if not the ultimate allocations, following the end of the rate freeze period.

B. Rate Design

1. Calculating the CTC

The CTC is the ratemaking mechanism designed to recover uneconomic generating costs and other transition costs. Its level is determined one way or another according to the level of other rate elements and with the limitation imposed by the rate freeze mandated by AB 1890.

The utilities propose to calculate the CTC as the residual cost after calculating all other costs, including the PX price. Thus, the CTC would be equal to the difference between the rate at the rate freeze levels and the combination of all other costs – the PX price, the distribution rate, the transmission rate, the public purpose program surcharge and the nuclear decommissioning surcharge. The resulting actual level of the CTC cannot be known in advance. Accordingly, the utilities propose using real-time pricing and "truing up" the difference after completion of the settlements process with the ISO. Under the utility proposals, each customer would be charged for the CTC according to individual demand on an hourly basis. For direct access customers, the CTC would be calculated using the utility tariff schedule the customer would subscribe to if it were not a direct access customer, that is, the "otherwise applicable rate." Both direct access and full-service utility customers would experience CTC rates that vary in an inverse relationship to the PX price.

ORA, the Energy Commission, Enron and Southern Energy Retail Trading and Marketing (Southern) oppose the utilities' method of calculating the CTC for a variety of related reasons. Southern observes that under the utilities' proposal customers who pay market prices for generation supply will always pay the same total price for generation regardless of the PX price, masking hourly changes in the price and failing to provide meaningful price signals. It also observes that customers whose generation prices are fixed will pay a lower total price at the time of system peaks.

Southern believes customers will not have an opportunity to reduce their costs by shifting load to lower-priced periods, resulting in less efficient use of the electrical system. Southern proposes that the Commission mitigate this problem by requiring that the CTC be fixed over a specified period. In order to assure the rate freeze is not compromised by this pricing policy, it would have the Commission impose a cap on the CTC. It also proposes to create a balancing account to adjust for forecast errors and the cap.

Enron makes similar comments, believing that by creating distortions in the market the utility proposals will discourage direct access. Enron proposes that the price volatility which would result from utility proposals be mitigated with rate design measures. Enron and Southern propose, as an alternative to averaging the CTC, that marketers be permitted to pay the CTC directly to the utility and to have separate arrangements with their own customers for payment of the CTC. The process would not involve the utilities but be a private arrangement between customers and marketers. Southern also seeks information from the utilities with regard to the class average CTC to implement the proposal. Enron also argues that the utilities offer no rational justification for having the CTC vary with load since CTC recovers fixed costs which do not vary with load.

ORA opposes the utilities' residual calculation of the CTC proposal, believing that it will make hourly pricing, including "virtual direct access" impossible because customers would be charged the same total rate in each hour of a TOU period. ORA argues this compromises the Commission's objective to provide customers with market-driven prices signals during the transition period, consistent with D.95-12-063. Like Enron and Southern, ORA recommends calculating the CTC charge for TOU customers as a rolling average for each TOU period in the customer's billing period based on an average PX price and residual CTC rate calculated for the customer's otherwise-applicable tariff. The Energy Commission makes similar observations and supports ORA's recommended alternative.

Edison opposes proposals to forecast the PX price, believing that the task would be too difficult. Edison argues that the alternatives proposed by the parties overlook a potential conflict between AB 1890 and a non-hourly calculation of CTC that could lead some customers to pay a higher-than-tariff energy rate, a circumstance that would violate the rate freeze.

PG&E also raises concerns with averaging the CTC, arguing that it masks the total cost of energy and conflicts with provisions of AB 1890 that provide that direct access customers are not treated differently from utility full-service customers. SDG&E observes that the utilities' method is the only one proposed on the record that assures customer bills will not change due to CTC collection, as it claims is required by AB 1890.

We understand the concerns raised by the parties with regard to the utilities' proposals to set the CTC residually. It appears that in fact the result will be to mask or severely distort price signals, creating system inefficiencies, especially among those customers who may be able to shift loads and thereby reduce peak system demand. (The price signals incorporated in existing time-of-use rates of course would be preserved.) And customers will fail to realize cost savings from more efficient use of energy, an outcome which is contrary to our intent and to the intent of AB 1890.

The modifications Enron and Southern made to their proposals late in the proceeding eliminated some of the controversy with the utilities. That is, the utilities may implement their methods for calculating the CTC residually, and still accommodate to some extent marketers' concerns about CTC variability. However, we believe that these solutions and the utilities' proposed residual method for calculating CTC would create an extra hurdle that might discourage prospective non-utility energy providers from participating in the California energy market. The utilities' proposals for real-time residual calculation of CTC would potentially require alternative providers to undertake substantial CTC forecast risk in order to offer attractive energy prices. At a minimum, the utility proposals would increase the degree of sophistication necessary to develop attractive direct access or departing load service arrangements.

To prevent any potential barriers to entry of prospective non-utility energy providers and to ensure implementation of effective time-differentiated price signals that have long been one of the paramount goals of our electric restructuring initiatives, we will reject the utilities' proposals. Instead, we will modify ORA's proposal by implementing an averaged, ex-post, energy cost for utility service customers that in turn—through residual calculation—provides an averaged CTC rate for all customers. Calculations of the averaged energy costs and the derived averaged CTC charges will be made for each rate class.

Averaging is done first on a weekly basis, and then a rolling average of usually four weeks is calculated to cover the different monthly billing cycles for different customers. The series of resulting approximately one-month averages of PX energy costs is used to calculate residually the corresponding averaged CTC on a billing-cycle basis. We believe that a month is the minimally-acceptable period for calculating the averaged CTC. However we are open to proposals for *longer* averaging periods and for proposals that use *forecasted* PX energy costs. We invite parties to collaborate in a workshop format to reach consensus on a proposal that would have a longer averaging period, and/or use a forecast of PX energy costs, and submit such a proposal to us for our consideration no later than October 1, 1997.

In the weekly averaging, utilities shall use hourly PX energy costs in each week and class load profiles for each rate class (the profiles including both utility service and direct access customers) to calculate an average PX energy cost for utility service customers in that rate group. Because billing cycles span multiple weeks, the average PX price for all calendar weeks from the time of a customer's previous billing through the week prior to the current billing shall be averaged to obtain a monthly average PX energy cost. The resulting averaged PX energy cost shall be applied to all sales to all utility-service customers served on existing rate schedules in each rate group during the billing month, with the averaged CTC charge calculated residually for each schedule and each billing month. Utilities shall implement this method in such a way that customers receiving service under TOU schedules continue to experience their respective frozen time-differentiated total rate levels. Utilities shall apply a similar averaging methodology to any other non-CTC functional rate components for utility service customers that vary with time.

The result of this approach is akin to an averaged CTC that will not fluctuate wildly over time and will be identical for utility-service (including virtual direct access), direct access and departing load customers taking service under the same tariff schedules used for purposes of CTC benchmarking. For bundled-service customers of the utilities, rates will not rise above frozen levels. We find that this design is consistent with the rate freeze provisions of AB 1890. We do not consider instances where customers *voluntarily* select a service option, like direct access or virtual direct access, that sometimes produces rates exceeding the rate they would have paid on June 10, 1996 to be in conflict with AB 1890. Customers always have the option of returning to a frozen-rate schedule if they wish.

Our approach is simpler to implement than the utilities' proposals. Utility proposals involve hourly metering of consumption—or proxying such hourly consumption with load profiles—of all direct access and departing load customers, then real-time residual CTC calculation, and finally application of this changing hourly CTC to the real-time load of each direct access and departing-load customer. In contrast, under the approach we adopt here, transition cost recovery calculation is simplified, because the residually-determined amount is a single, stable amount over monthly calculation periods. However, because the utility billing cycle varies for each customer over the week and month, some lag in the process of issuing bills may be required to accommodate our chosen approach for calculating the CTC. Utilities should address this issue in pro-forma tariffs that will be developed in preparation for the workshop to be held in August.

2. Virtual Direct Access

In previous orders we have addressed how customers who do not participate in direct access may opt for "virtual direct access" by relying on real-time (hourly) meters. In D.95-12-063, the Preferred Policy Decision setting out the framework for electric restructuring, we stated our support for virtual direct access and real-time pricing because it would increase system efficiency and offer customers improved service options. In D.97-05-040, our Direct Access decision, we reiterated these goals. We noted earlier the problem with the utilities' proposals for calculating CTC that they mask the energy cost signals that customers need in order to take advantage of real-time metering options like virtual direct access. Our adopted levelized CTC calculation methodology in fact expressly is designed to overcome that problem by permitting variations in PX energy costs to "shine through," so to speak. In turn, consumers with real-time metering options like virtual direct access can use that valuable information to lower their total energy costs.

Of course, it will be important for utilities to provide new, virtual direct access services and tariff offerings for their customers that would promote the efficient use of energy. We therefore direct the utilities to propose such services and tariffs in their compliance tariff filings. Section 378 allows utilities to offer to propose new services and tariff offerings that accurately reflect, among other things the costs of providing those services. Such new, virtual direct access services would not be bound by the rate-freeze provisions of AB 1890 that apply to existing services.

3. CTC Impact on Baseline and CARE Rates

Baseline rates provide lower cost electricity for the first units residential customers use. Subsequent units are priced at somewhat higher levels. Low income customers receive discounted rates pursuant to the "CARE" program. The parties address the issue of how to set baseline and CARE rates to include the CTC and retain the rate differentials following the rate freeze period. PG&E and SDG&E propose a rate differential between baseline and other rates for the distribution rate and CTC so that the rate structure after the CTC is removed from the utility's rates would continue to reflect the CARE and baseline rate structure. Edison proposes the differential be reflected only in the CTC during the term of the rate freeze. ORA argues that Edison's approach does not properly anticipate the period following the rate freeze with regard to baseline rates. TURN/UCAN add that Edison's proposal compromises Commission objectives to establish cost-based rates. Under Edison's proposal, the only difference in rates between baseline customers and other customers would be in the level of the CTC.

Edison comments that customers will pay the same baseline and nonbaseline rates, regardless of the differential, because total rates will not change. Edison proposes to revisit the matter at the end of the rate freeze period.

We agree with ORA and TURN/UCAN that Edison's proposal to reflect baseline differentials only as part of the CTC is contrary to our objective to promote cost-based rates. We therefore adopt the proposals of PG&E and SDG&E for baseline and CARE rates. Edison shall amend its rate design for baselines rates accordingly.

4. Edison's CARE Surcharge

Edison proposes to impose a separate CARE surcharge on customer bills rather than include the costs and discounts of the CARE program in the public purpose programs surcharge. TURN/UCAN oppose this separate surcharge, arguing that Section 381(a) anticipates the establishment of the public purposes program surcharge to fund programs described in Section 382, among others. CARE is described in Section 382.

We concur with TURN/UCAN's interpretation of Section 381(a) and direct Edison to include all CARE program costs, including the discount, in the public purpose programs surcharges.

5. Edison's Domestic Seasonal Rate Adjustment

Edison currently has a Domestic Seasonal Rate Adjustment which guarantees that Edison recovers distribution and generation revenues which would otherwise fluctuate seasonally. ORA testified that the adjustment would potentially be anticompetitive because it is not available to competitors who may be subject to seasonal revenue fluctuations as well. ORA argues that differing summer and winter distribution rates could create market distortions that could create subsidies or hurdles for competitors. ORA proposes that Edison should be required to justify any proposed continuation of this adjustment in its tariff filing.

We have some concerns about ratemaking conventions which are designed for the sole purpose of shielding the utilities from risk and which might otherwise create market distortions. We cannot however determine how ORA would have Edison further justify the adjustment. We do not eliminate the adjustment here because doing so may change Edison's risk, an outcome we have stated we will avoid in this proceeding. We may however reconsider the adjustment in the next proceeding which addresses ratemaking issues for Edison.

6. Bill Credit Procedures

The utilities propose to implement the 10% rate reduction for residential and commercial customers by providing a bill credit. While no party objects to the proposal, ORA believes customers who receive the rate reduction and subsequently switch to a tariff not subject to the associated charge for paying off the rate reduction bonds, should refund the original rate reduction amounts.

We reject ORA's proposal on the basis that it sets up a potentially complex mechanism without any providing any substantial benefit to customers, because the number of customers who are able to take advantage of such a scheme unfairly is likely to be small. The utilities bill credit proposal is adopted.

We also adopt the proposal of the Merced Irrigation District to the effect that a customer who leaves a utility system in order to take service from any other entity which must impose a public purpose program surcharge pursuant to Section 385 shall not pay the initial utility's surcharge going forward because the customer will be paying the charge to the new entity.

7. PX Energy Charges

The calculation of PX energy charges is critical to residually determining the CTC. Each utility presented a method for this calculation which forms the basis for the credit provided to direct access customers. Edison proposes using the weighted average of the day-ahead and hour-ahead prices, adjusted for administrative costs, settlements, ancillary services, and congestion fees.

Edison proposes to add settlement costs to the PX energy charge in the following billing periods. Edison is the only party who made detailed proposals on how the PX energy price should be trued up after the ex-post settlement from the

ISO/PX are received and how the result should be reflected in customers' bills. The Commission adopts Edison's proposal for reflecting ex-post settlements.

Edison also proposes that all customers should pay for the costs of unaccounted for energy. If the ISO bills the utility for all unaccounted for energy, Edison would recover these costs from all customers. If FERC approves the proposal contained in the March 31 FERC filing to allocate unaccounted for energy to scheduling coordinators, the cost of unaccounted for energy should be treated in a similar manner as treatment of settlement costs. Edison proposes to incorporate costs that are assigned to all scheduling coordinators into the PX energy charge and to credit these costs to direct access customers. We will direct that any ISO costs that are assigned exclusively to the utility for services provided on behalf of all customers should be recovered from all customers, regardless of generation provider.

8. Rate Design for Distribution, Public Purpose Programs and Nuclear Decommissioning Costs

We adopt Edison's proposal to design and escalate nongeneration rates according to the method approved in its nongeneration PBR decision, and then subtract the transmission rates from the nongeneration rates to arrive at distribution rates. In addition, the utilities' proposed tariffs should present rate design methods for public purpose programs and nuclear decommissioning costs so that these costs are recovered from customers through non-time differentiated energy charges specific to each rate group.

9. Unbundling and Continuation of Flexible Pricing Options

Edison proposes to adapt its Flexible Pricing Options (FPOs) to accommodate the PX market structure and direct access so that several of its FPOs can remain open to new customers, including direct access customers, upon commencement of the PX. We will adopt these uncontested proposals, which Edison believes are necessary in order for it to administer the FPOs as of January 1, 1998.

10. Large Power Rate Design Issues

CLECA/CMA raised issues concerning Edison's escalation methodology for nongeneration rates, large power rate design and treatment of interruptible credits.

a. Escalation for Nongeneration PBR Base Rates

CLECA/CMA believe Edison's proposal to keep T&D demand charges fixed is unwise because it is increases in demand, rather than energy consumption, that cause higher T&D costs.

Due to the rate freeze mandated by AB 1890, Edison was prohibited from escalating customer and demand charges above its June 10, 1996 levels. Therefore, in its PBR filing, all escalation amounts were converted to a cents-per-kWh basis and added entirely to base energy charges. The PBR decision specifically authorized all rates to be escalated by CPI-X. Consistent with the PBR decision, it is reasonable to escalate the energy charges.

Edison's methodology of converting the escalation of nongeneration PBR base rates entirely into energy charges, even for schedules with demand and customer charges, is consistent with current adopted methodology and is adopted.

b. Aligning Schedule Revenues with the Allocated Revenue Requirement

In instances where Edison's development of nongeneration marginal cost-based customer and demand charges produce more revenue than the allocated revenue requirement for a particular schedule, Edison has reduced the nongeneration time-related demand charges to align schedule revenues with the allocated revenue requirement. Without this adjustment, nongeneration energy rates would become negative. Therefore, it is reasonable to reflect this adjustment in the next most variable charges.

In instances where marginal cost-based customer and demand charges for a schedule do not collect the allocated revenue requirement, the imposition of an energy charge is appropriate.

CLECA/CMA suggested using an EPMC factor to increase all transmission and distribution components. This is inconsistent with how the nongeneration PBR base rates, which are escalated to arrive at 1998 rates, are established. Also, adjusting these components would result in prices that deviate from marginal costs. We adopt Edison's methodology.

c. Edison's Flexible Pricing Options Should Be Unbundled and Made Available to Both Bundled Utility Customers and Direct Access Customers

Edison presented testimony on two aspects of its FPOs. The first aspect is the unbundling of these rate options to make them compatible with the availability of a PX price and the Commission's desire to have the PX price be reflected in customers' rates without any mark-up or modification by the utility. The second issue relates to making these options available to direct access customers. Customers who may elect to take service on these options should not be precluded from engaging in direct access transactions. From a technical and ratemaking point of view, there are no impediments to making these options available to direct access customers. Edison plans to present the revised tariffs to accomplish this object in the tariff phase of this proceeding. We adopt Edison's proposal.

d. Interruptible Credits

Edison has proposed to reflect the interruptible credit in a lower CTC charged to interruptible customers. CLECA/CMA made an alternative proposal to reflect some of this credit in a lower transmission charge. We adopt Edison's proposal in part because we have no jurisdiction over transmission charges and seek to resolve the matter here.

11. Distribution Line Losses

Edison has proposed to use average loss factors to calculate costs associated with line losses, and to recover these costs from all customers as a non-PBR distribution rate component. PG&E and SDG&E did not address this issue.

CLECA/CMA proposed a formula for computing hourly distribution line loss factors. CLECA/CMA developed these factors from Edison's average factors used in Edison general rate cases. ORA supports the CLECA/CMA methodology.

Testimony of ORA, CLECA/CMA and Edison concerning the settlements process supports the importance of using accurate hourly allocation factors in minimizing system-wide costs and ensuring accurate cost allocations that avoid cost shifting. We believe CLECA/CMA's methodology accurately represents these losses and therefore we adopt it. We direct PG&E and SDG&E to file similar proposals for implementing hourly distribution line loss calculations in their Advice Letter filings.

IX. Master Meter Issues

A. *Minimum Average Rate Limiter (MARL)*

WMA proposes to reduce the MAR (or MARL for PG&E) for master-metered customers who elect direct access. The MAR applies to master-metered customers only and establishes a minimum level for recovery of energy costs and the Commission fee. WMA proposes that the utilities reduce the MAR to reflect the utilities' cost of purchased power. WMA observes that the utilities will still be able to recover purchased power costs authorized in the CTC.

Edison and PG&E oppose WMA's proposal. PG&E responds that AB 1890 mandated a rate freeze at levels in effect on June 10, 1996 which would be violated under WMA's proposal. PG&E explains that it would treat master-metered customers electing direct access just as it would treat all other customers, that is, master-metered customers would only pay that portion of the MARL attributable to costs not related to PX energy. Edison makes similar comments, adding that WMA's proposal could result in the utility selling its master-metered customers its services at a negative rate.

We do not adopt WMA's proposal because it would effectuated a change in rates which is contrary to AB 1890. As they propose, the utilities will reflect the PX energy cost by way of a credit to the customer who chooses direct access.

B. *Funding Costs to Implement Direct Access for Tenants*

WMA proposes that master-metered customers be offered an additional discount on submetering to fund additional capital and operating expenditures park owners require to implement direct access for their tenants. Specifically, WMA says direct access will create new costs for park owners because of the need for them to educate and train customer and park employees, to change tenants' bills, to accommodate competitors making sales presentations to park residents, and to provide for direct access metering.

PG&E and Edison oppose WMA's proposal on the basis that it would violate the rate freeze required by AB 1890 by providing a discount to submetered customers beyond that allowed by AB 1890.

We concur with the utilities' position that WMA's proposal represents a rate change which is contrary to AB 1890. We understand that some customers may incur transactions costs as a result of electric restructuring. WMA's proposal requires that either the utilities or other customers should bear those costs in higher electric bills, an outcome which we cannot adopt. If WMA believes park owners should receive higher submetering discounts because the cost of service to them will be lower or because the utilities' avoided costs will be higher under direct access, it may propose discount changes in forums where we consider utility revenue requirements.

C. Tariff Modifications for Master-Metered Customers

WMA proposes that utility tariffs specify that tenants' bills will not be unbundled by the park owners. Edison opposes the suggestion, observing that tenants of master-metered park owners are not Edison customers and therefore utility tariffs should not specify the relationships between park owners and tenants.

We reject WMA's proposal because, as Edison points out, it assumes a relationship between the utility and the park tenants that does not exist. Park owners are responsible for the bills they render to their tenants, consistent with existing law.

X. Bill Format Issues

To effectuate unbundling, the utilities will need to change their customer bills to provide adequate information to customers about their energy choices and the services they are receiving. The parties agree that the information should be clear and avoid confusion. Generally, the utilities proposed billing formats in consideration of these objectives, although the extent of information the utilities proposed to provide was the subject of some dispute. The utilities emphasized that modifying their billing systems will require substantial time and effort. Edison in particular urges a simple bill format and warns the Commission that it may be unable to program its billing system in time if complex changes to the system are required.

We appreciate the utilities' concerns regarding the timing of billing format changes. Below, we propose certain minimal bill format changes which should be implemented January 1, 1998 and require the utilities to provide additional detail over time. As a practical matter, we do not believe most customers will require the most detailed level of information proposed here in the immediate future. As competition in energy markets takes hold, customers will require more and better information, which our adopted schedule will accommodate.

A. Rate Reduction Credits

All three utilities propose to reduce rates to residential and small commercial customers by 10% beginning January 1, 1998. By ruling dated January 31, 1997, the assigned ALJ determined that the Commission would consider methods for doing so in this proceeding. The reduction is one condition of the utilities' ability to recover stranded investment through the CTC.

All of the utilities propose to implement the rate reduction as a bill credit. SDG&E proposes to provide a bill credit to eligible customers. PG&E proposes to reduce all unit charges by 10%, a proposal SDG&E believes may be difficult to administer. TURN proposes that the utilities be required to charge the entire discount to the CTC in order to assure that customers receive the full benefits of the reduction intended by AB 1890. Consistent with TURN's recommendation, PG&E will account for the reduction as CTC. ORA states it is satisfied with the utility proposals with the modifications PG&E made in its supplemental testimony.

We will adopt the utility proposals to reduce eligible customers' bills by 10% and to account for the bill credit as reduced CTC for direct access customers, the credit will be applied to a customer's bill under its otherwise-applicable schedule before the bill is reduced by the PX cost.

B. Power Exchange Prices

Bills must provide pricing information which will permit customers to make reasoned choices between energy suppliers. ORA and Farm Bureau observe that PX prices must be included on customer bills in order for customers to evaluate competitors' bids.

PG&E proposes that for direct access customers served with the use of statistical load profile and with full service customers, the price that appears on the bill will be the average PX prices for the month. For direct access customers, the prices will be based on the hourly PX price and the hourly-specific loads for each customer.

Recognizing that settlement prices from the PX will not be available for 60 days, PG&E proposes that customer bills estimate the PX price and be subject to a true-up the following month. PG&E also proposes that the Commission reconsider this approach if it does not appear to accomplish Commission objectives.

Edison proposes to include the PX energy price it paid during the billing cycle, based on the customer class load profile. Direct access customers would also show a credit for customer-specific avoided energy costs based on the PX energy price. SDG&E proposes providing customers the option of receiving PX price information, arguing that TURN/UCAN's proposal to provide all customers the price and emission profile of all energy sources will create too much confusion.

ORA recommends that SDG&E's bill include the PX price.

We adopt the proposals of Edison and PG&E and direct SDG&E to include PX pricing information on its bills, either in the format presented by Edison or PG&E. As SDG&E proposes, customers should be provided additional information whenever the utility has the information.

C. Extent of Unbundling Rates on Bills

DOD proposes that the utilities be required to unbundle rates for various rates elements, including transmission, distribution, public benefit program costs, nuclear decommissioning costs, demand-side management (DSM), CTC, and PX expenses. The Energy Commission would require a similar level of detail, observing that AB 1890 stated an intent that the utilities provide separate charges for transmission, distribution, transition costs, environmental costs, and low-income program costs.

TURN/UCAN also recommend that the components of the CTC be identified on bill inserts. The categories are uneconomic nuclear generation, uneconomic fossil fuel generation, uneconomic purchased power contracts and "other." The percentage of the charges for each of these categories would be determined based on the outcome of Phase 2 of the CTC proceeding (Application (A.) 96-08-001, et al.).

CAL-SLA propose that Edison and PG&E follow SDG&E's lead and (1) provide customers with the option of a detailed or simple bill, (2) separate the PX price from the CTC on each bill, and (3) include the "Reed Schmidt Footnote" on each bill, which explains that the generation charge is based on the costs of purchases through the PX which are subject to competition and which would inform the customers that electricity may be purchased from another supplier. CAL-SLA suggests that if PG&E and Edison are unable to implement sound billing information practices by January 1, 1998, they should be ordered to do so no later than June 1, 1998. ORA generally supports CAL-SLA's recommendations.

PG&E would not go this far in unbundling rates. As discussed earlier, PG&E is not prepared to unbundle rates on January 1, 1998. Edison objects as well, arguing that listing such items as CTC and nuclear decommissioning charges do not enhance the customer's ability to compare value. Edison also observes that providing such information is costly.

We believe customers are entitled to information about the services and investments for which they are paying. We balance this view with the cost of providing such information and the confusion it can create for customers who simply want to pay their bills with the confidence that they correctly identify the services received. We adopt the recommendations of parties who suggest that bills should separately identify the following components: energy, transmission, distribution, CTC, public purpose programs and nuclear decommissioning costs. These rate elements should be fully unbundled consistent with the functional rate tables presented by PG&E in Appendices 4A and 4B in Exhibit 1. We also adopt the Reed Schmidt Footnote. The utilities shall therefore include on their bills an easily-identified explanation of the PX price as follows: "This charge is based on the weighted average costs for purchases through the Power Exchange. This service is subject to competition. You may purchase electricity from another supplier." We reject proposals to go further at this time. In order to provide the utilities adequate time to identify these charges, we will direct them to include the charges on bills no later than June 1, 1998. Prior to the date of unbundling, the utilities shall provide information regarding PX prices.

D. Other Bill Information

ORA proposes that the utilities periodically provide information on resource mix and environmental characteristics of electricity purchases. TURN/UCAN propose a similar type of information but with considerably more detail regarding emission profiles for various resources, consistent with the National Association of Regulatory Utility Commissions' (NARUC's) Resolution No.17. SDG&E objects to intervenor proposals to provide such information.

We believe the type of information TURN/UCAN and ORA would have the utilities offer with regard to air emissions is important and useful. Nevertheless, we do not believe all customers will find it useful. We will direct the utilities to collect the data required to provide the information to customers who request it and provide the information annually in a bill insert. Utility bills should notify customers that the information is available beginning January 1, 1999. The Energy Commission notes in its comments that the utilities will need to obtain the information from the ISO/PX. While we cannot here order the ISO/PX to track the information, we urge them to do so. If they do not, the utilities should notify the Executive Director of their inability to provide the associated customer information.

Findings of Fact

1. On March 19, 1997, CIU, CLECA, CMA, DOD, ORA, PG&E, SDG&E, and Edison filed a "Joint Motion for Adoption of Retail Transmission Rate Stipulation." No party protested the motion or the stipulation.

2. In its June 5, 1997 filings before the FERC, the Commission stated its support for the proposition that the FERC should defer to the Commission's recommendations regarding revenue allocations and rate design for unbundled retail transmission service, as proposed by the March 19 stipulation.

3. The application of differing revenue allocation and rate design to retail transmission and retail distribution rates might result in significant shifts in cost responsibility between retail customer classes, contrary to the provisions of AB 1890 which prohibit the Commission from approving cost shifts between customer classes.

4. The rate design and revenue allocation methods set forth in the March 19 stipulation appear consistent with Commission practice and policy for each utility and appear to be consistent with FERC's open access policies.

5. The utilities propose that the Commission adopt distribution revenue requirements equal to the difference between the total nongeneration revenue requirements and the transmission revenue requirements adopted by the FERC.

6. One of the consequences of electric industry restructuring is the increased role of the FERC in setting transmission rates and revenue requirements.

7. The utilities' proposed method for developing distribution revenue requirements would effectively require this Commission to ignore FERC findings regarding the reasonableness of utility revenue requirements proposals and to include in distribution revenue requirements costs the utilities have identified as related to transmission.

8. Establishing a distribution revenue requirement which is premised entirely on the findings of FERC would be a delegation of Commission authority to FERC.

9. If the potential for disparate ratemaking decisions of the FERC and the Commission creates risk for the utilities, it is risk already anticipated by AB 1890 and previous Commission decisions.

10. The utilities will discontinue their role in electric dispatch and system control beginning January 1, 1998. Nevertheless, the utilities seek to recover revenue requirements previously authorized to conduct generation dispatch and control activities.

11. The utilities have not demonstrated that the revenue requirements for dispatch and control will be required beginning January 1, 1998.

12. The utilities' cost of capital may change in various operations as a result of industry changes. The need for an associated review is not urgent.

13. SDG&E's escalation method applies recently adopted PBR escalation rates.

14. Permitting the utilities to recover generation costs in the CEMA would provide a competitive advantage to the utilities in generation markets.

15. Permitting the utilities to recover generation costs in the HSCLS would provide a competitive advantage to the utilities in generation markets.

16. Some costs of generation may be fixed over the short or medium term.

17. The utilities propose to allocate all fixed A&G costs to distribution rates.

18. All generation companies will incur fixed costs.

19. All generation companies must ultimately recover all of their fixed costs in order to be viable.

20. The utilities will have opportunities to recover fixed costs following the introduction of direct access.

21. Edison proposes to include certain SONGS and Palo Verde generation costs in distribution rates.

22. Edison and SDG&E propose to include in distribution rates the costs of marketing and customer service that they have not demonstrated are attributable to distribution operations.

23. Some of the costs associated with franchise fees and uncollectibles are attributable to generation operations.

24. PG&E proposes to create a nonbypassable charge and associated balancing account for Diablo Canyon ICIP prices that exceed market prices. PG&E does not provide any analytical or policy support for its proposal.

25. The Commission has not heretofore approved of PG&E's proposed Diablo Canyon ICIP charge.

26. Edison proposes MAM, a nonbypassable surcharge and associated balancing account for the costs and revenues associated with 39 separate accounts, including the costs associated with its fuel pipeline terminal company which are currently included in Edison's PBR.

27. SDG&E proposes a MAM associated balancing account for the costs and revenues of several separate accounts related to generation.

28. The MAM and Diablo Canyon ICIP accounts would reduce utility risk from that anticipated by AB 1890 and previous Commission decisions.

29. Many of the costs in Edison's proposed MAM account are unrelated to distribution operations.

30. As part of a comprehensive regulatory program, AB 1890 authorized recovery of uneconomic utility generation costs by way of the CTC which is to be eliminated no later than March 31, 2002. AB 1890 set forth exceptions to the recovery of uneconomic generation costs by way of the CTC.

31. The uneconomic generation costs included in the MAM accounts and the Diablo Canyon ICIP account are not among the exceptions listed in AB 1890 of uneconomic generation costs which are recoverable by way of the CTC.

32. PG&E proposes to replace the existing ECAC and ERAM accounts with a TRA which serves the same purpose and functions the same as an ERAM account by guaranteeing recovery of authorized revenues.

33. The Commission is considering ERAM and ECAC accounts in the Electric Tariff Streamlining workshops.

34. Edison's revenue allocation proposal, which applies the EPMC method on the basis of total revenues, is closest to existing revenue allocation methods and avoids an embedded cost approach.

35. AB 1890 provides that residential and commercial customers receive a 10% rate discount and pay off the rate reduction bonds issued by the utilities.

47. WMA's proposal to reduce the MAR would effectively reduce rates for master-metered customers, in violation of AB 1890's rate freeze provisions.

48. WMA's proposal to discount rates to master-metered customers to fund direct access costs is contrary to AB 1890's rate freeze provisions.

49. WMA's proposal to require tariffs to specify that tenants' bills will not be unbundled by park owners wrongfully assumes a relationship between the utility and the park tenants that does not exist and intervenes in the business relationship between park owners and their tenants.

50. Hourly distribution line loss factors are essential for minimizing system-wide costs and ensuring accurate cost allocation that avoids cost shifting.

51. Requiring the utilities to charge the 10% discount mandated by AB 1890 to the CTC will assure that customers receive the full benefits of the discount.

52. Providing PX price information on customer bills and a notice regarding the availability of competitive energy suppliers will promote customer education about energy alternatives.

53. Customers would benefit by having separately identified charges for energy, transmission, distribution, CTC, public purpose programs and nuclear decommissioning costs.

54. Not all customers are likely to find useful information regarding emission profiles for various generation resources.

55. PG&E and BART agree that PG&E should continue to bill BART conjunctively for bundled and direct access services.

Conclusions of Law

1. The Commission should support the transmission revenue allocation and rate design proposals included in the Joint Motion filed on March 19, 1997 and adopt those proposals to the extent permitted by law governing state and federal jurisdiction.

2. Section 454 requires the Commission to issue findings with regard to the reasonableness of utility rates.

3. AB 1890 retains the Commission's authority to allocate costs among customers.

4. The Commission should adopt the distribution revenue requirements proposed by the utilities in this proceeding with the adjustments set forth in this decision.

5. The Commission should reduce distribution revenue requirements by amounts allocated to generation dispatch and control.

6. The Commission should defer to the findings of R.92-03-050 and subsequent ratemaking proceedings in considering line extension allowance rules and their effects on revenue requirements.

7. The utilities should be ordered to propose modifications to their cost of capital or justify existing cost of capital revenue requirements in the generic cost of capital proceeding.

8. The Commission should adopt SDG&E's method for escalating revenue requirement.

9. The utilities should be prohibited from entering into their CEMA accounts any costs associated with generation.

10. The utilities should be prohibited from entering into their HSCLS accounts any costs association with generation.

11. The utilities' revenue requirements for distribution should be reduced to recognize a fair allocation of A&G costs between distribution, transmission and generation, as set forth in this decision.

12. SDG&E's and Edison's revenue requirements for distribution should be reduced to recognize a fair allocation of customer service and marketing costs between distribution, transmission and generation, as set forth in this decision.

13. The utilities' distribution revenue requirements should be reduced to recognize a fair allocation of FF&U costs between distribution, transmission and generation, as set forth in this decision.

14. The rules of statutory construction provide that where exceptions to a general rule are specified by statute, other exceptions are not to be implied or presumed.

15. PG&E's request to create a nonbypassable charge for Diablo Canyon ICIP costs that are above market prices should be denied. Regulatory treatment of associated

costs should be considered in the proceeding addressing appropriate components of the CTC.

16. Edison's request to create a nonbypassable surcharge and balancing account for costs set forth in its MAM proposal should be denied. Associated costs should be allocated to various functions as set forth in this decision.

17. SDG&E's request to create a nonbypassable surcharge and balancing account for costs set forth in its MAM proposal should be denied. Associated costs should be allocated to various functions as set forth in this decision.

18. PG&E's request to create a TRA should be denied.

19. The utilities should be ordered to apply the 10% discount to residential and small commercial customers on all types of rate schedules and to recover the cost of paying off the rate reduction bonds from the same classes of customers.

20. Marketers and brokers should be permitted to negotiate with their energy customers the method by which customers will pay the CTC to them.

21. The utilities' proposals to develop the CTC should be rejected. Instead, the Commission should adopt the modified ORA methodology described in section VIII.B.1 of this decision.

22. Deriving an averaged CTC residually for each rate class by ex post averaging for utility-service customers all non-CTC functional rate components that vary with time does not violate the rate freeze articulated in Section 368 of the PU Code.

23. The utilities should be required to allocate the costs of public purpose programs using the system average percent method.

24. The utilities should be required to create a rate differential between baseline and other rates for both distribution rates and the CTC so that the rate structure after the CTC is removed would continue to reflect the baseline rate structure.

25. Hourly distribution line loss factors should be implemented effective January 1, 1998.

26. The utilities' public purpose program surcharges should include all CARE program costs, consistent with Sections 381 and 382.

27. The utilities should be required to functionalize the rates on customer bills consistent with this decision no later than June 1, 1998.

28. Utility tariffs should specify that a customer who leaves the utility system to be served by an entity which must impose a public purpose surcharge pursuant to Section 385 shall not thereafter be required to pay the utility's public purpose program surcharge.

29. The utilities shall reflect the 10% rate reduction to small commercial and residential customers by way of a reduction to the CTC.

30. The utilities should be required to provide information regarding the PX price on customer bills.

31. Customer bills should separately identify charges for energy, transmission, distribution, the CTC, public purpose programs and nuclear decommissioning costs no later than June 1, 1998 as set forth in this decision.

32. The utilities should be required to collect data necessary to provide customers with information about air emissions profiles of various generation resources. Utility bills should notify customers of the availability of the information beginning January 1, 1999.

33. The utilities should be required to include on customer bills an explanation of the PX price and the availability of alternative electricity suppliers, as set forth in this decision.

34. PG&E should continue to bill BART conjunctively for bundled and direct access services.

35. Edison's proposal to incorporate costs for administrative and other unlift charges that are assigned to all scheduling coordinators into the PX energy charge and to credit these costs to direct access customers is reasonable and should be adopted.

36. Edison's large power rate design proposals are reasonable and should be adopted

37. SDG&E should update its advice letter after its 1998 PBR revenue requirement change is approved, requesting of a 1998 distribution revenue requirement to become effective January 1, 1998.

ORDER

IT IS ORDERED that:

1. The transmission rate design and revenue allocation proposals set forth in the Joint Motion filed March 16, 1997 and set forth in Appendix A are approved and adopted to the extent permitted by law governing state and federal jurisdiction.

2. The Joint Motion filed March 16, 1997 is granted to the extent set forth herein and to the extent the Commission has acted in accordance with the recommendations of the Joint Motion.

3. The revenue requirements for Southern California Edison Company (Edison) set forth in Appendix B are adopted.

4. The revenue requirements for Pacific Gas and Electric Company (PG&E) set forth in Appendix D are adopted.

5. The revenue requirements for San Diego Gas & Electric Company (SDG&E) set forth in Appendix C are adopted.

6. Edison shall file an application on May 8, 1998, seeking review of its cost of capital for 1999 test year.

7. SDG&E shall file an application on May 8, 1998, seeking review of its cost of capital for 1999 test year.

8. PG&E shall file an application on May 8, 1998, seeking review of its cost of capital for 1999 test year.

9. PG&E, Edison, and SDG&E shall not enter into their respective Catastrophic Events Memorandum Accounts any costs related to generation.

10. PG&E, Edison, and SDG&E shall not enter into their respective Hazardous Substance Clean-up and Litigation Cost Accounts any costs related to generation.

11. Utility requests to create nonbypassable surcharges and balancing accounts not identified in Assembly Bill (AB) 1890 are denied.

12. PG&E, Edison, and SDG&E shall file tariffs within 15 days of the effective date of this order which incorporate the provisions of this order and which shall not include any changes to tariffs not anticipated or required by this order. The tariffs shall reflect

the revenue requirements for each utility set forth in Ordering Paragraphs herein and shall:

a. Provide the 10% discount mandated by AB 1890 to residential and small commercial customers on all types of rate schedules and recover the cost of paying off the rate reduction bonds from the same classes of customers.

b. Permit marketers and brokers to negotiate with their energy customers the method by which their customers will pay the competitive transition charge (CTC) to them.

c. Derive an averaged CTC residually by ex post averaging of energy and other non-CTC functional rate components that vary over time using the modified ORA methodology described in Section VIII.B.1 of this decision.

d. Allocate the costs of public purpose programs using the system average percent method.

e. Create a rate differential between baseline and other rates for both distribution rates and the CTC so that the rate structure after the CTC is removed reflects the baseline rate structure.

f. Include in public purpose program surcharges all California Alternative Rate for Energy program costs, consistent with Public Utilities (PU) Code §§ 381 and 382.

g. Provide that customer bills will include rates, charges and other information consistent with this decision no later than June 1, 1998. Prior to the time they unbundle rates, the utilities shall specify PX prices as set forth in this decision.

h. Specify that a customer who leaves the utility system to be served by an entity which must impose a public purpose surcharge pursuant to PU Code § 385 shall not thereafter be required to pay the utility's public purpose program surcharge.

i. Reflect the 10% rate reduction to small commercial and residential customers by way of a reduction to the CTC.

j. Incorporate other rate design and revenue allocation provisions set forth in this decision.

13. PG&E, Edison, and SDG&E shall collect data necessary to provide customers with information about air emissions profiles of various generation resources. Utility

bills shall quarterly notify customers of the availability of the information beginning January 1, 1999.

14. SDG&E shall file an advice letter no later than October 15, 1997 to update the authorized distribution revenue requirement as shown in Appendix C, Table 1 to reflect the adopted 1997 (Resolution E-3401) and proposed 1998 PBR escalation rates and other PBR-related adjustments. The advice letter filing shall reflect the adjustments for distribution portion of the adopted PBR adjustments using the methodology consistent with this decision. This Advice Letter shall be updated after the proposed 1998 PBR escalation rates are adopted.

[illegible]. PG&E shall continue to bill BART conjunctively for bundled and direct access services.

16. Applications (A.) 96-12-009, A.96-12-011, and A.96-12-019 are held open pending development of a streamlined A&G reallocation procedure by the Assigned Commissioners.

This order is effective today.

Dated August 1, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners

I will file a concurring opinion.

/s/ JESSIE J. KNIGHT, JR.
Commissioner

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Identify and Separate Components of Electric Rates, Effective January 1, 1998 (U 39-E)	Application 96-12-009 (Filed December 6, 1996)
Application of San Diego Gas & Electric Company (U 902-M) For Authority to Unbundle Rates and Products	Application 96-12-011 (Filed December 6, 1996)
In the Matter of the Application of Southern California Edison Company (U 388-E) Proposing the Functional Separation of Cost Components for Energy, Transmission and Ancillary Services, Distribution, Public Benefit Programs and Nuclear Decommissioning, To Be Effective January 1, 1998 In Conformance With D.95-12-036 as Modified by D.96-01-009, the June 21, 1996 Ruling of Assigned Commissioner Duque, D.96-10-074, and Assembly Bill 1890	Application 96-12-019 (Filed December 6, 1996)

RETAIL TRANSMISSION RATE STIPULATION

Dated: March 18, 1997

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RETAIL TRANSMISSION RATE STIPULATION

1. PARTIES

The Parties to this Stipulation ("Stipulation") are California Industrial Users, California Large Energy Consumers Association, California Manufacturers Association, Department of Defense/Department of the Navy/Federal Executive Agencies, Office of Ratepayer Advocates (ORA), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) (referred to hereinafter collectively as "Parties" or individually as "Party").

2. RECITALS

2.1 Edison is an investor-owned public utility in the State of California and is subject to the jurisdiction of the California Public Utilities Commission ("Commission" or "CPUC") with respect to providing electric service to its CPUC-jurisdictional retail customers.

2.2 ORA is the office of the Commission responsible for advocating on behalf of the interests of utility customers.

2.3 PG&E is an investor-owned public utility in the State of California and is subject to the jurisdiction of the CPUC with respect to providing electric and gas service to its CPUC-jurisdictional retail customers.

2.4 SDG&E is an investor-owned public utility in the State of California and is subject to the jurisdiction of the CPUC with respect to providing electric and gas service to its CPUC-jurisdictional retail customers.

3. STIPULATION

In consideration of the mutual obligations, promises, covenants and conditions contained herein, the Parties agree to support approval by the Commission of this Stipulation in this proceeding as further described in Section 5.

3.1 Purpose

In Order No. 888, FERC asserted that it has jurisdiction over unbundled transmission service provided by public utilities to wholesale and retail customers, and ordered that customers participating in voluntary or state-ordered retail direct access programs must obtain their unbundled transmission service under a non-discriminatory transmission tariff on file with FERC. However, FERC also indicated in Order No. 888 that it would be willing to defer to state recommendations regarding rates, terms, and conditions for retail transmission service where appropriate to meet local concerns provided that these recommendations are consistent with FERC's open access policies.

The Parties to this Stipulation believe that there are substantial "local concerns" in California which argue strongly for the CPUC retaining the ability under the new industry structure to develop class revenue allocations and rate designs for unbundled retail transmission service. The Parties therefore request that the CPUC in this proceeding support the position that, upon implementation of the new industry structure, FERC should defer to the CPUC's adopted methodologies for developing retail transmission revenue allocations and rate designs for the applicable California investor-owned utilities for, at a minimum, the first two years of the new industry structure.[1]

The Parties also recommend adoption by the CPUC of the transmission revenue allocation and rate design methodologies[2] as proposed by the utilities in their December 6, 1996 filings with the CPUC (Applications 96-12-009, 96-12-011, and 96-12-019), as supplemented by Appendix A of this Stipulation. Upon issuance of a CPUC decision on retail transmission revenue allocation and rate design, the Parties recommend that the CPUC support a request to FERC for deference to the CPUC's determination as to the rates for unbundled retail transmission service. The utilities in their WEPEX Phase II filings at FERC, expected in March 1997, will include their proposed retail transmission rates based on the proposed transmission revenue requirement with the expectation that the CPUC will support deference.

3.2 Background

This Stipulation is the result of extensive discussions among members of the Ratesetting Working Group ("RWG"), which was officially recognized by the CPUC in an Assigned Commissioner's Ruling dated June 21, 1996. These discussions have also involved participants in the

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[1] This request does not include the determination of the revenue requirement for the transmission facilities under ISO control or any pricing provisions relating to transmission congestion, ancillary services, losses, and ISO administration which, pursuant to the current WEPEX proposal, are to be recovered from scheduling coordinators under FERC-jurisdictional rates.

[2] For purposes of this filing, revenue allocation and rate design methodologies refer to the allocation among retail customer classes. The parties have not agreed on the allocation between FERC and CPUC jurisdictional facilities. The rate design methodologies described herein are illustrative in that the actual rates filed before the FERC may differ from the rates contained in the December 6, 1996 filings to reflect updated billing determinants, allocation determinants and transmission revenue requirements.

Transmission and Ancillary Services Definition Team during development of the FERC WEPEX Phase II filing. Among the issues addressed by the RWG is the design of unbundled retail transmission rates or access charges.

PG&E, SDG&E, and Edison each filed with the CPUC on December 6, 1996, proposals for unbundling the components of their revenue requirements and the associated retail revenue allocation and rate design. The utilities expressed their belief that, under the new industry structure, the determination of the revenue requirement for unbundled retail transmission associated with facilities whose control will be transferred to the Independent System Operator ("ISO") will become the responsibility of FERC. However, since the utilities are not expected to file proposed transmission revenue requirements for 1998 with FERC until March 1997, the utilities provided in their December 6 filings "illustrative" estimates of the transmission revenue requirements. The utilities also provided class revenue allocations and rate designs for the unbundled transmission function based upon previously adopted CPUC methodologies for retail customers. Thus, the filings were predicated upon continuing CPUC responsibility for developing class revenue allocation and rate designs for all retail transmission service, which would be subsequently included in the applications to FERC.

3.3 Joint Recommendations

3.3.1 <u>The CPUC should support the position in this proceeding that FERC should defer to the CPUC's recommendations regarding the rates for unbundled retail transmission service provided under the new industry structure by the investor-owned utilities, as such deference will facilitate the successful implementation of the state's electric industry restructuring efforts.</u>

Under this proposal, FERC would authorize the total transmission revenue requirement of the jurisdictional utility, the allocation of that revenue requirement to retail and wholesale customers, and the transmission rate design ("access charge") to be assessed to non-self-sufficient wholesale utilities and to wholesale wheeling through and out of the ISO.[3] FERC would also be responsible for developing rates for transmission congestion, ancillary services, and ISO administration which will be paid by scheduling coordinators. FERC would defer to the CPUC's recommendations for developing retail class revenue allocation and unbundled retail transmission rate designs to recover the FERC-authorized retail transmission revenue requirement. Final authorized CPUC rates for FERC-jurisdictional service would be filed with FERC and subject to

[3] This assumes adoption by FERC of the utility-specific transmission access charge as proposed by the utilities in their April 29, 1996 filing with FERC. If FERC decides to allocate and recover a portion of the transmission revenue requirement from generators as opposed to solely from customer loads, then this stipulation would not seek deference for the design of the transmission rate applied to generators.

FERC acceptance. Such deference is appropriate and necessary for the reasons discussed below.

The CPUC has been and is currently responsible for developing transmission rates for all retail customers of investor-owned utilities. In the Parties' view, such complete assumption of responsibility by FERC over ratemaking for unbundled retail transmission service in California is inappropriate because it may result in cost-shifting, at least in the short term.

Parties are particularly concerned about the significant differences between FERC and CPUC ratemaking methodologies. While the CPUC has relied upon marginal cost-based approaches, FERC has traditionally utilized methodologies such as 12-CP or load ratio share, and for point-to-point transmission service, contract demands.[4] The FERC approaches have been established over the years predicated on wholesale service where a utility developed allocations and transmission rate design for a few, relatively large wholesale utility customers. On the other hand, CPUC methodologies have been developed specifically with full

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[4] The 12-CP cost allocation methodology is based on customers' contributions to monthly system peaks and is a traditional embedded cost methodology. Either a marginal cost or an embedded cost revenue allocation or rate design may use alternative factors to allocate revenue responsibility. The CPUC believes that its marginal cost allocations reflect cost causation among retail customers, and when a single factor is used for a function like transmission, the pertinent factor could be used in an embedded cost allocation with the same final result. This is the case for SCE and SDG&E, and the cost-based allocator determines the cost allocation rather than the issue of whether a marginal or embedded cost approach is used. For PG&E, the revenue allocation in effect as of June 10, 1996, is based on a geographically differentiated marginal cost analysis, in which the marginal costs have the effect of weighting factors among peak loads that were also analyzed on a geographic basis.

consideration of the millions of retail customers who are provided service under the retail rate schedules. A shift in ratemaking for unbundled retail transmission from the CPUC's adopted methodologies to FERC methodologies would be likely to result in significant shifts in transmission cost responsibility between retail customer classes. Since cost shifting is prohibited under AB 1890, and the total rates to retail customers are to be frozen through 2001, any dramatic shift in transmission revenue allocation to retail customer classes or in retail transmission rate design, will necessitate an equal and opposite change in other rate components. To the extent that FERC adopts a rate structure for unbundled retail transmission based on billing parameters not provided for under current retail schedules, such as 12-CP or load ratio share, it would be impossible for the CPUC to residually develop the remaining rate structure to comply with the AB 1890 prohibition on cost shifting.[5] In this situation, cost shifting for some customers would be unavoidable. In the view of the Parties, FERC deference to the CPUC's recommendations is required to ensure compliance with key provisions of AB 1890 (i.e., no cost shifting and the rate freeze).

There is also the issue of consistency with the ratemaking for the transmission provided to full service utility retail customers

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[5] Many of FERC's traditional approaches for revenue allocation and rate design cannot even be implemented here. For example, FERC's approach to charge transmission customers based on the customer's load ratio share requires that the customer have a time-of-use meter. The vast majority of retail customers in California do not have such metering.

under the new industry structure. Where service is not "unbundled" retail transmission service, it would remain the jurisdiction of the CPUC. Different ratemaking approaches due to split jurisdiction for retail customers could have significant impacts on the implementation of the California program. A key provision embodied in AB 1890 is that similar full service utility retail customers and direct access retail customers of a utility are to pay the same transmission and distribution rates (Section 368(b). The utilities' network transmission pricing model proposed at FERC, where the end-user of a jurisdictional utility is responsible for paying the transmission access charge, is designed to allow adherence to that provision of AB 1890. Given that split jurisdiction exists under the new industry structure, the Parties believe that compliance with Section 368(b) of AB 1890 can best be achieved by requesting at the outset that FERC defer to the CPUC's recommendations for developing retail transmission rates for unbundled retail transmission customers.

The Parties' believe that their recommendation for FERC deference described above is consistent with FERC's open access policies and comparability principles, since the CPUC can and will ensure that all similarly situated retail direct access and bundled full service customers of a jurisdictional utility pay the same transmission access charges, subject to FERC's final approval.

3.3.2 <u>**The CPUC should adopt in this proceeding the retail transmission revenue allocation and rate design methodologies reflected in the utilities' December 6, 1996 filings, as supplemented by Appendix A to this proposed stipulation, for use in developing unbundled transmission rates for retail customers under the new industry structure.**</u>

The methodologies for developing retail transmission revenue allocation filed in this proceeding by the three utilities on December 6, 1996, are consistent with the methodologies previously adopted by the CPUC and were utilized to develop the total retail rate levels in effect on June 10, 1996. Although the CPUC's rate design methodologies are based on the total (bundled) rate level, the utilities' unbundled transmission rate design proposals, as supplemented by Appendix A to this Stipulation, are consistent with their interpretation of CPUC decisions and raise no issues that the Parties contest for purposes of implementing the CPUC's restructuring of the electric utility industry. AB 1890 freezes retail rates of the three utilities at the June 10, 1996 levels, so consistency and avoiding cost shifting among customer classes support that the June 10, 1996 revenue allocation and rate design methodologies be utilized for development of unbundled retail transmission rates under the new industry structure. Thus, the Parties recommend that the CPUC adopt the retail transmission revenue allocation and rate design methodologies as filed by the utilities on December 6, 1996, as supplemented by Appendix A to this settlement proposal. A summary of the methodologies which should be adopted for each utility is provided below.

3.3.2.1 PACIFIC GAS & ELECTRIC COMPANY

PG&E is allocating the transmission revenue requirement based on a full equal percentage of marginal cost ("EPMC") allocation. The EPMC allocation factor is equal to a rate schedule's transmission marginal cost revenue divided by the total transmission marginal cost revenue.[6]

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[6] PG&E is using transmission marginal costs as adopted in D.92-12-057 and updated in D.95-12-051.

Each schedule's transmission marginal cost revenue requirement is determined by the sum of Bulk Transmission, Transmission Planning Project (TPP) and Transmission Planning Area (TPA) marginal cost revenue. Generally speaking, Bulk Transmission costs reflect facilities providing 230 and 500 kV service. TPP costs can be assigned to a specific area or set of substations. TPA costs are also assignable to smaller specific areas or sets of facilities. PG&E assigns these costs to each class as follows:

First, for Bulk Transmission marginal cost revenues, PG&E multiplies the marginal Bulk Transmission capacity cost by (1) system-average loss factors and (2) Shortage Value (SVAL)-weighted coincident loads for each schedule. The SVAL loads represent customers' value of reliability for service at the time of the system coincident peak.

Second, for TPP marginal cost revenues, PG&E multiplies the TPP marginal costs by (1) TPP-specific capacity loss factors; and (2) TPP-specific Peak Coincident Allocation Factor (PCAF)-weighted loads for each rate schedule. These rate schedule totals by area are summed to determine the total TPP marginal cost revenue for each schedule. These total marginal cost revenues are then scaled to the test-year level by first dividing by weather-normalized kWh to yield a dollar-per-kWh marginal cost, and then multiplying by the schedule's test-year sales to produce TPP marginal cost revenue by schedule.

Third, for TPA marginal cost revenues, PG&E multiplies the transmission marginal costs by (1) TPA-specific capacity loss factors; and (2) TPA-specific PCAF-weighted loads to get TPA-specific marginal cost revenue for each schedule. The resulting marginal cost revenue sums are the area-marginal costs revenue by schedule across all TPAs. These are then scaled to the test-year level by first dividing by weather-normalized kWh to yield a dollar per kWh marginal cost, then multiplying by the schedule's test-year sales to produce TPA marginal cost revenue by schedule.

Continued on the next page

A schedule's transmission allocation equals the product of the FERC-authorized transmission revenue requirement and the schedule's EPMC allocation factor.

PG&E's Unbundling Application, Appendix 4A, provides parties with a description of how PG&E would allocate the FERC-authorized transmission revenue requirement to current rate schedule components. In general, PG&E approached the formulation of the functionalized rates in a decremental fashion.

Starting with current rates, and assuming a rate schedule with a full array of rate components (i.e., energy, demand and customer charges), demand charges for the transmission function were calculated to collect the allocated transmission costs. Consistent with current rates, demand charges are established on a usage (rather than a reservation basis). Accordingly, transmission charges may vary from customer group to

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For the purposes of assigning TPA and TPP marginal costs revenues, PCAF-weighted loads are derived by weather-normalizing hourly annual loads for a planning area and reordering them by size, from largest to smallest, creating load duration curves. The method then selects all loads that are 80 percent or more of the largest load in the load duration curve (but not less than 10 hours and not more than 800 hours of load). Next, a weighting factor is calculated for each selected hour by dividing the hour's excess load over 80 percent of the maximum load by the sum of all selected excess loads. The TPA and TPP causative factor is then calculated by summing the products of the hourly weighting factor and the load of each selected hour.

The final step sums the Bulk Transmission, TPA, and TPP marginal costs assigned to each class. The embedded transmission revenue requirement is assigned to each schedule by the proportion of that schedule's transmission marginal cost revenue responsibility to the total system transmission marginal cost revenue.

customer group depending on the usage characteristics of the group. On schedules where a combination of demand charges exist (for example, on-peak demand charges, maximum demand charge, etc.), transmission costs are spread equally (that is, the same percentage of each demand charge is assigned to transmission, or if only energy charges are available, the same percentage of each energy charge is assigned to transmission) across all demand charges.[7]

3.3.2.2 SAN DIEGO GAS & ELECTRIC COMPANY

SDG&E proposed to use the marginal cost revenue from the 1996 ECAC Decision, which supports the class revenue allocations used for the June 10, 1996 rates, as the basis for allocating the unbundled transmission revenue requirement. The FERC authorized transmission revenue requirement would be allocated to rate classes by multiplying the transmission unit marginal cost times the rate class's transmission allocation determinants. Each rate class's marginal transmission cost revenue responsibility would then be

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[7] Due to limitations with its current billing system, PG&E proposed not to use functionalized transmission rates for billing purposes during the rate freeze period. Rather, PG&E will show on monthly customer statements the portion of the total electric bill represented by transmission services (in dollar terms). The portion of the total electric bill for transmission service would reflect the EPMC allocation of revenue to a specific rate schedule. This billing system limitation in no way affects the actual amounts billed to direct access customers relative to what they would have paid if this billing limitation did not exist. Other parties have taken issue with PG&E's proposal for the timing of when PG&E should be required to bill customers using functionalized transmission rates. The CPUC will decide this issue in this proceeding.

scaled up or down using an EPMC (i.e. scaling) factor developed based on the ratio of the total transmission marginal revenue to the total authorized transmission revenue requirement. The Schedule AL-TOU and Agriculture rate classes would be subdivided based on rate schedules in order to account for the rate structure differences in the design of the Transmission Access Charge rates.

Rates would be designed to collect the transmission revenue requirement allocated to each rate class. For rate schedules with demand and energy charges the Transmission Access Charge rate design would be recovered by allocating 90 percent of the rate class's transmission revenue requirement to the demand rate group and 10 percent to the energy rate group. The demand and energy charges would be adjusted to reflect the applicable loss factors.

For schedules with simple demand charges (not time or seasonally differentiated) unit charges would be based on each rate group's allocated transmission revenue requirement divided by the rate class's kW and kWh sales forecast.

For rate schedules with time-differentiated demand charges the unit charges would be based on each rate group's allocated transmission revenue requirement divided by the rate class's kW and kWh sales forecast.

The level of the monthly Non-Coincident and On-peak Charges would be established based on SDG&E's currently-adopted methodology for determining coincident-related and non-coincident-related demand costs. Unit marginal demand and energy costs would be scaled up or down to collect the transmission revenue requirement allocated to each rate group.

For rate schedules with time-differentiated and seasonally differentiated demand charges the unit charges would be based on each rate group's allocated transmission revenue requirement divided by the rate class's kW and kWh sales forecast. The level of the monthly Non-Coincident Demand Charge and seasonal On-Peak Demand Charges would be established based on SDG&E's currently-adopted methodology for determining coincident-related and non-coincident-related demand costs, and the Loss of Load Probabilities (LOLP) in the summer and winter costing periods. Unit marginal demand and energy costs would be scaled up or down to collect the transmission revenue requirement allocated to each rate group.

For rate schedules with seasonally differentiated coincident-peak demand charges the unit charges would be based on each rate group's allocated transmission revenue requirement divided by the rate class's kW and kWh sales forecast. The Transmission Access Charge rate design would reflect a seasonal allocation of costs based on LOLP's, and seasonal coincident-peak demand determinants. Unit marginal demand and energy costs would be scaled up or down to collect the transmission revenue requirement allocated to each rate group.

For SDG&E's real time pricing rate schedules, the signal based unit charges would be based on the transmission revenue requirement allocated to coincident peak demand plus an energy rate component. The allocation of the coincident peak demand transmission revenue requirement to each signal period would continue to be based on hourly system LOLP's. The allocated transmission revenue requirement would then be divided by the kWh sales forecast for each signal period. The Non-Coincident Demand Charge would be determined by dividing the non-coincident demand transmission revenue requirement by the rate class's kW sales forecast. The allocation of the transmission demand revenue requirement would be based on SDG&E's currently-adopted methodology for determining coincident-related and non-coincident-related demand costs. The energy charges would be based on the allocated transmission revenue requirement divided by the rate class's kWh sales forecast. The unit charges would be scaled up or down to collect the transmission revenue requirement allocated to each rate group.

For rate schedules without demand charges, transmission rates would be designed on an equal cents per kWh basis by dividing the allocated transmission revenues by total kWh sales for the rate class.

For Street Lighting rate schedules the Lighting kWh Transmission Access Charge would equal the allocated transmission revenue requirement divided by the adopted Lighting kWh sales forecast. The fixed monthly charge would be based on estimated monthly average kWh use by lamp type multiplied by the Lighting kWh Transmission Access Charge rate.

3.3.2.3 SOUTHERN CALIFORNIA EDISON COMPANY

The FERC authorized transmission revenue requirement would be allocated to rate groups by multiplying the transmission revenue requirement by each rate group's percentage of marginal transmission cost revenue responsibility ("MTCRR") authorized in Phase 2-A of Edison's 1995 GRC.[8]

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[8] A rate group's MTCRR equals the product of the annual per kW marginal transmission cost and a measure of the rate group's contribution to peak demand on the transmission system known as Peak Capacity Allocation Factor (PCAF) weighted demand. PCAFs are proportional to the amount by which a region's load exceeds 80% of its annual peak and are scaled so that the annual total for each region equals 1.0. The PCAF for hour i is calculated by the following formula:

$PCAF_i = (kW_i - 0.8 * kW^p)/\Sigma(kW_i - 0.8 * kW^p)$, if $kW_i > 0.8 * kW^p$,

and $PCAF_i = 0$, if $kW_i \leq 0.8 * kW^p$,

where kWi is the sum of individual customer demands in a region during hour i, and kW^p is the annual region coincident peak.

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Rates would be designed to collect the transmission revenue requirement allocated to each rate group. For rate schedules with demand charges, the demand charges would be set equal to the marginal transmission costs adopted in Phase 2-A of Edison's 1995 GRC and then scaled uniformly so that the charges recover the allocated transmission revenue requirement by rate group. If the scaled charge would exceed the total demand charge, it would be set equal to the total demand charge, and the remaining transmission revenue requirement would be collected on an equal cents per kWh basis.

For rate schedules with time-related demand charges, 90% of annual marginal transmission costs would be considered coincident demand-related and converted to time of use demand charges based on the relative loss of load probability occurring during each time period. 10% of annual marginal transmission costs would be considered noncoincident demand-related and converted to monthly non-time related demand charges by dividing the annual value by 12. The time-related and non-time-related marginal cost demand charges would

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Hourly loads for each rate group as measured by load research sample data are multiplied by the PCAF for each hour in a region, summed across all hours and regions, and then divided by the annual average kW for the rate group to determine its PCAF weighted demand factor. The PCAF weighted demand factor multiplied by test year annual average kW for the rate group equals the test year PCAF weighted demand used to determine MTCRR.

be equally scaled to yield demand charges that recover the transmission revenue requirement allocated to the rate group.

For rate schedules that contain a non-time related demand charge or a connected load charge and do not contain time-related demand charges, 100% of marginal transmission costs would be converted to a monthly non-time related demand charge by dividing the annual value by 12. The non-time-related marginal cost demand charge would be scaled to yield a demand charge that recovers the transmission revenue requirement allocated to the rate group.

For rate schedules without demand charges, transmission rates would be designed on an equal cents per kWh basis by dividing the allocated transmission revenues by total kWh sales to the rate group.

3.3.3 **The CPUC should file comments with FERC after the Phase II WEPEX filings are made by the utilities, supporting a request that FERC defer to the CPUC's recommendation for development of revenue allocations and rate designs for unbundled retail transmission service for at least the first two years after implementation of the new industry structure.**

As discussed above, the Parties believe that it is appropriate and necessary for the CPUC to continue to develop retail transmission revenue allocations and rate designs after the implementation of the new industry structure. The Parties therefore recommend that the CPUC file comments with FERC after the Phase II WEPEX filings are made by the utilities, supporting a request that FERC defer to the CPUC's adopted methodologies for unbundled retail transmission revenue allocation and rate design for at least the first two years after the implementation of the new industry structure.[9] The Parties believe that CPUC comments are necessary to obtain FERC acceptance of the utilities' deference proposal.

The Parties believe that the CPUC's request for deference should be for a period of at least two years after the implementation of the new industry structure, since two years is the minimum period of time that the utility-specific transmission access charge as proposed by the utilities in the April 29, 1996 FERC filing is expected to be in effect. Under AB 1890, the methodology for the transmission access charge is subject to review and possible revision at the end of this two-year period. However, many of the reasons which support the position of FERC deference would suggest that such deference would be appropriate for the entire period of the retail rate freeze mandated by AB 1890, i.e., 2001, and it may be

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[9] This stipulation relates to the portion of that revenue requirement that is to be recovered through an access charge applied to retail customer's load. If FERC decides that a portion of the transmission revenue requirement will be recovered from generators, as opposed to solely from retail loads, then this stipulation is not asking for deference for the generation rate.

appropriate for the CPUC to request deference for the longer period.

4. SIGNATURE DATE AND TERM OF STIPULATION

This Stipulation shall become binding on the signature date.

5. REGULATORY APPROVAL

The Parties shall use their best efforts to obtain Commission approval of the Stipulation. The Parties shall jointly request the Commission: (1) approve the Stipulation without change; and (2) find the Stipulation to be reasonable and in the public interest.

6. NON-PRECEDENT

Consistent with Rule 51.8 of the Commission's Rules of Practice and Procedure, this Stipulation is not precedential.

7. PREVIOUS COMMUNICATIONS

The Stipulation contains the entire Stipulation and understanding between the Parties as to the subject matter of this Stipulation, and supersedes all prior agreements, commitments, representations, and discussions between the Parties. In the event there is any conflict between the terms and scope of the Stipulation and the terms and scope of the accompanying joint motion, the Stipulation shall govern.

8. EFFECT OF SUBJECT HEADING

Subject headings in this Stipulation are inserted for convenience only, and shall not be construed as interpretations of the text.

9. **GOVERNING LAW**

This Stipulation shall be interpreted, governed, and construed under the laws of the State of California, including Commission decisions, orders, and rulings, as if executed and to be performed wholly within the State of California.

10. **SIGNATORIES**

The undersigned represent that they are authorized to sign the Retail Transmission Rate Stipulation on behalf of the named Party.

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: Catherine E. Yap
Catherine E. Yap

CALIFORNIA MANUFACTURERS ASSOCIATION

By: M. Catherine George
M. Catherine George

DEPARTMENT OF DEFENSE/ DEPARTMENT OF THE NAVY/ FEDERAL EXECUTIVE AGENCIES

By: Norman Furuta
Norman J. Furuta

OFFICE OF RATEPAYER ADVOCATES

By: Catherine A. Johnson
Catherine A. Johnson

PACIFIC GAS AND ELECTRIC COMPANY

By: Andrew L. Niven
Andrew L. Niven

SAN DIEGO GAS & ELECTRIC COMPANY

By:
Vicki L. Thompson

SOUTHERN CALIFORNIA EDISON COMPANY

By:
James M. Lehrer

CALIFORNIA INDUSTRIAL USER

By:
Philip A. Stohr

Dated: March 18, 1997
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SOUTHERN CALIFORNIA EDISON COMPANY
REAL TIME PRICING SCHEDULE 1996
Hourly Transmission Prices ($/kWh)

HOUR ENDING @ (PST)	EXTREMELY HOT SUMMER WEEKDAY Daily High * Temp >=95°	VERY HOT SUMMER WEEKDAY Daily High Temp. 91-94°	HOT SUMMER WEEKDAY Daily High Temp. 85-90°	MODERATE SUMMER WEEKDAY Daily High Temp. 81-84°	MILD SUMMER WEEKDAY Daily High Temp. <=80°	HIGH COST WINTER WEEKDAY Daily High Temp>90°	LOW COST WINTER WEEKDAY Daily High Temp. <=90°	HIGH COST WEEKEND Daily High Temp. >=78°	LOW COST WEEKEND Daily High Temp <78°
1 a.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
2 a.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
3 a.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
4 a.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
5 a.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6 a.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
7 a.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8 a.m.	0.01553	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
9 a.m.	0.00813	0.00317	0.00507	0.00021	0.00000	0.00000	0.00000	0.00000	0.00000
10 a.m.	0.03031	0.01204	0.01648	0.00317	0.00076	0.00000	0.00000	0.00000	0.00000
11 a.m.	0.09094	0.03485	0.04183	0.01014	0.00153	0.00355	0.00022	0.00000	0.00000
12 noon	0.17448	0.07985	0.06337	0.00760	0.00321	0.00266	0.00008	0.00026	0.00000
1 p.m.	0.34897	0.12928	0.10604	0.01943	0.00199	0.00621	0.00060	0.00009	0.00000
2 p.m.	0.41329	0.15082	0.13371	0.02260	0.00887	0.00710	0.00049	0.00051	0.00000
3 p.m.	0.48574	0.19328	0.15674	0.02831	0.00627	0.02307	0.00170	0.00017	0.00000
4 p.m.	0.43103	0.12738	0.13752	0.02281	0.00474	0.04791	0.00168	0.00060	0.00000
5 p.m.	0.27725	0.05640	0.07795	0.01162	0.00153	0.02307	0.00095	0.00085	0.00000
6 p.m.	0.15822	0.03992	0.01817	0.00148	0.00061	0.02218	0.00022	0.00009	0.00000
7 p.m.	0.18188	0.02155	0.01817	0.00084	0.00000	0.01065	0.00068	0.00017	0.00000
8 p.m.	0.05101	0.01014	0.01436	0.00169	0.00000	0.00621	0.00035	0.00009	0.00000
9 p.m.	0.00518	0.01014	0.00106	0.00000	0.00000	0.00355	0.00008	0.00000	0.00000
10 p.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
11 p.m.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Midnight	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

* Daily maximum recorded temperature at the LA Civic Center. (END OF APPENDIX A)

Appendix B
Table 1

Southern California Edison
Development of Distribution Revenue Requirement

(Thousands of Dollars)

Line No.			
1	Edison Nongeneration Revenue Requirement Request		2,027,881
2	Remove Transmission Revenue Requirement	(211,054)	
3	Edison requested Distribution Revenue Requirement		1,816,827
4			
5	Adjustments:		
6			
7			
8	Load Dispatching/PX-ISO Costs	(10,830)	
9	Adjust for Multifactor Allocation of Common Generation A&G	(25,152)	
10	Remove SONGS/PV A&G Costs	(24,451)	
11	Reduce Customer Service & Marketing Cost	(7,735)	
12	Change FF&U Allocation	(7,471)	
13	MAM-related Adjustment:		
14	Change in Distribution Revenue Requirement	(73,511)	
15			
16			
17	**Adjusted Distribution Revenue Requirement**		**1,667,677**

Line 1/ Edison Ex. 12, p. 18, using Base PBR starting point developed in A. 96-07-009 (1996 dollars)

Appendix B
Table 2
SOUTHERN CALIFORNIA EDISON COMPANY

REVENUE ALLOCATION
(Thousands of Dollars)

CUSTOMER / RATE GROUP	NON-GENERATION MARGINAL COST REVENUES ($M)	NON-GENERATION MARGINAL COST REVENUES (%)	EPMC ALLOCATION OF REV. REQ. ($M)	ADD NON-ALLOC REVENUES ($M)	TOTAL NON-GENERATION BASE REV. REQ. ($M)
DOMESTIC:	930,370.7	45.6641%	737,228.7	0.0	737,228.7
LIGHTING-SMP:					
GS-1	179,979.0	8.8337%	142,616.0	0.0	142,616.0
TC-1	2,831.7	0.1390%	2,243.8	0.0	2,243.8
TOTAL NON-DEMAND	182,810.7	8.9726%	144,859.8	0.0	144,859.8
GS-2	471,989.0	23.1660%	374,005.6	2,647.5	376,653.1
TOU-GS-2	65,030.2	3.1918%	51,530.1	926.2	52,456.4
TOTAL DEMAND	537,019.1	26.3577%	425,535.7	3,573.8	429,109.5
TOTAL LIGHTING-SMP	719,829.8	35.3304%	570,395.5	3,573.8	573,969.3
LARGE POWER:					
TOU-8-SEC	146,716.0	7.2011%	116,258.2	3,065.6	119,323.8
-PRI	135,506.5	6.6509%	107,375.8	2,742.7	110,118.5
-SUB	31,876.0	1.5645%	25,258.6	1,932.0	27,190.6
TOTAL LARGE POWER	314,098.4	15.4164%	248,892.6	7,740.4	256,632.9
AG & PUMPING:					
PA-1	34,568.5	1.6967%	27,392.2	0.0	27,392.2
PA-2	13,521.4	0.6637%	10,714.4	104.2	10,818.6
TOU-PA-5	2,109.0	0.1035%	1,671.2	12.0	1,683.2
AG TOU	14,304.3	0.7021%	11,334.8	299.9	11,634.7
TOTAL AG & PUMPING	64,503.2	3.1659%	51,112.5	416.1	51,528.6
STREET & AREA LGT:	8,622.2	0.4232%	6,832.3	41,484.9	48,317.2
TOTAL	2,037,424.3	100.0000%	1,614,461.5	53,215.1	1,667,676.7

NOTE: NON-ALLOCATED REVENUES CONSIST OF POWER FACTOR AND STREETLIGHT REVENUES.

Appendix B
Table 3

SOUTHERN CALIFORNIA EDISON
REALLOCATION OF PROPOSED MISCELLANEOUS ADJUSTMENT MECHANISM
(Thousands of Dollars)

Line No.			
1	**Reallocate to Distribution Revenue Requirement**		
2	Base Rate Performance Memo Account (BRPMA)		0
3	TOU-PA-6 Memo Account		0
4	Nongeneration Revenue Sharing Memo Account		0
5	Optional Pricing Adjsutment Clause (OPAC)		0
6	Electric & Magnetic Fields (EMF) Program Cost Recovery		738
7	RCRA & Incremental return		(65,995)
8	Non-Utility Affiliate Credit		(11,969)
9	Catastrophic Event-Related Cost Recovery		3,715
10		Subtotal	(73,511)
11			
12	**Reallocate to Generation Revenue Requirement**		
13	Fuel Oil Inventory Carrying Costs		3,669
14	Disputed Arizona Property Taxes		0
15	El Paso Electric Bankruptcy (EPEB) Memorandum Account		0
16	SONGS 2&3 and Palo Verde Shutdown O&M and Unamortized Fuel Expense		0
17	Income Tax Component of Contribution Memo Account		0
18	Arbitration Memo Account (AMA)		0
19	Nuclear Related Special Assessments		0
20	YUMA-Axis		(1,902)
21	Catalina Diesel Fuel Costs		1,734
22	Catalina RECLAIM Trading Credits Cost Recovery/Revenue Credit		155
23	Hydro Pumped Storage Costs Recovery		2
24	Energy Line Loss Adjustments		0
25	Edison Pipeline & Terminal Co. (EPTC) Fuel Oil Pipeline Revenue Sharing		(1,643)
26	Haz Substance Clean-up and Litigation Cost (HSCLC) Balancing Account		5,935
27	Nuclear Unit Incentive Procedure Incentives/Penalties		14,595
28		Subtotal	22,565
29	**Reallocate to Nuclear Decommissioning Revenue Requirement**		
30	Songs 1 Shutdown O&M		11,458
31	DOE Decontamination & Decommissioning Fees		4,633
32	Spent Nuclear Fuel Storage Costs		3,263
33		Subtotal	19,354
34	**Reallocate to Public Purpose Programs Revenue Requirement**		
35	Women, Minorities & Disabled Veterans Business Enterprises Cost Recovery		621
36	Demand Side Management Adjustment Mechanism		0
37	Demand Side Management Tax Change Memo Account		0
38	Envest Pilot Program Adjustment Mechanism (EPPAM)		0
39	Economic Development Adjustment Clause (EDAC)		0
40	Research Development & Demonstration (RD&D) Royalties--Revenue Credit		(3,119)
41	Demand Side Management Incentives Recovery		1,251
42	Electric Vehicle (EV) Memorandum Account		2,616
43	Low Emission Vehicles--O&M Cost Recovery		5,744
44		Subtotal	7,113
45	**Reallocate to Transmission Revenue Requirement**		
46	Devers to Palo Verde 2 Transmission Line Recovery		2,235
47		Subtotal	2,235
48			
49	**Total Reallocated**		(22,244)

(END OF APPENDIX B)

APPENDIX C

Table 1

San Diego Gas and Electric Company - Electric Department

Authorized Distribution Revenue Requirements

Line No.			1/1/98 Rev. Reqt. ($000)
1	Authorized Base Rate Revenues ('93 GRC, T&D):	$	717,641
2	Adjustments:		
3	Transmission Wheeling Charges	$	(4,181)
4	Local Dispatching Costs	$	(5,534)
5	A&G: Generation Fixed Costs	$	(4,906)
6	Customer Services and Marketing Costs	$	(983)
7	Miscellaneous Adjust. Mechanism (MAM)	$	(8,100)
8	Franchise Fees & Uncollectibles (FF&U)	$	(6,387)
9			
10	Subtotal Adjustments	$	(30,091)
11			
12	Subtotal Auth. Base Rev. Reqt. ('93 GRC, T&D)	$	687,550
13	ERAM Balancing Revenue (T&D)	$	24,916
14	CARE Program	$	(1,019)
15	Total T&D Revenue Requirements	$	711,447
16	LESS:		
17	Transmission Revenue Requirements	$	121,382
18	ERAM Balancing Revenue for Transmission	$	3,779
19	Public Benefit Programs:		
20	DSM	$	32,000
21	RD&D	$	4,000
22	Renewable	$	12,000
23	CARE	$	8,465
24	Subtotal Public Benefit Programs	$	56,465
25			
26	Nuclear Decommissioning Rev. Reqt.	$	22,038
27	DOE D&D Fees & SONS1 Costs	$	6,158
28	Subtotal Nuclear Related Rev. Reqt.	$	28,196
29			
30	Total Authorized Distribution Rev. Reqt.	$	501,625

APPENDIX C

Table I

San Diego Gas and Electric Company - Electric Department

Authorized Distribution Revenue Requirements

Note:

Line 1 -- $691,283 + $12,100 + $14,258 (1996$)
('93 GRC shown in Exh.16 plus trans. wheeling chgr. & MAM account, see Exh. 80).
-- not include SDG&E's 1997 T&D portion of the authorized PBR adjustments and the 1998 proposed PBR adjustments.
-- to be updated in SDG&E's advice letter filing to reflect SDG&E's 1997 & 1998 PBR adjustments for T&D.

Line 3 -- $12,100 - $7,919 (1996$)
(Exh. 80 less the amount included in SDG&E's 3/1/97 FERC filing).

Line 4 -- $3,724 + $1,810 (1996$)
(direct costs in Acct. 556 & 561 plus A&G & common plant, see Exh. 64 & TURN's Opening Brief, p. 20).

Line 5 -- $78,681 - $78,681 / 87.665% x (1 - 17.8%) = $78,681 - $73,775 (1996$)
(use the allocation factor of 17.8% for generation as shown in Exh. 55).

Line 6 -- see Exh. 63.
-- $5,521 x 17.8% (1996$)
(use the allocation factor of 17.8% for generation as shown in Exh. 55).

Line 7 -- $14,258 - Line 27 (1996$)
(Amount shown in Exh. 80 less DOE D&D Fees & SONGS 1 Costs).

Line 8 -- $19,16 ÷3 (1996$, 33% of total FF&U).

Line 18 -- see Exh. 28.

Line 27 -- $1,040 + $733 + $4,385 (1996$)
(DOE Decontamination & Decommissioning Fees plus SONGS 1 Spent Nuclear Fuel Storage Costs & SONGS 1 Shutdown O&M Costs)
-- from workpaper provided to the Energy Division for the MAM account in Exh. 80.

Line 30 -- to be updated in SDG&E's advice letter filing to reflect SDG&E's 1997 & 1998 authorized PBR adjustment for T&D.

APPENDIX C

Table II

San Diego Gas & Electric Company

Electric Department

Allocation of Unbundled Revenue Requirement Components

Line No.	Customer Class	6/10/96 Adopted FPIM Avg Rate (¢/KWhr)	AB1890 Avg Rate (¢/KWhr)	Adopted ECAC Sales (GWhrs)	AB1890 Revenue ($000's)	Distribution Revenue ($000's)	Transmission Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
						1/	(Illustrative)
1	Residential	11.242	10.118	5,854.76	592,370	244,018	59,420
	Commercial/Industrial:						
2	Schedule A	11.864	10.678	1,918.95	204,898	78,283	19,062
3	Schedule AD	12.077	12.077	579.73	70,011	18,572	4,523
4	Schedule AL-TOU	8.474	8.474	6,698.65	567,628	141,678	34,500
5	Schedule A6-TOU	6.493	6.493	665.34	43,204	7,442	1,812
6	Subtotal	9.212	8.981	9,862.66	885,742	245,975	59,897
7	Agriculture	11.300	11.300	144.79	16,361	6,564	1,598
8	Lighting	11.043	11.043	79.76	8,808	5,068	467
9	System Total	9.985	9.430	15,941.97	1,503,281	501,625	121,382

Line No.	Customer Class	Public Goods Revenue ($000's)	Nuc. Related Revenue ($000's)	Rate Red Bonds Revenue ($000's)	Power Exchange Revenue ($000's)
		(g)	(h)	(i)	(j)
		2/	2/	(Illustrative)	(Illustrative)
10	Residential	22,955	11,658	54,980	152,224
	Commercial/Industrial:				
11	Schedule A	7,884	4,033	18,020	51,812
12	Schedule AD	2,419	1,240	0	14,377
13	Schedule AL-TOU	20,673	10,054	0	160,768
14	Schedule A6-TOU	1,656	765	0	15,303
15	Subtotal	32,631	16,092	18,020	242,259
16	Agriculture	570	290	0	2,896
17	Lighting	308	156	0	1,196
18	System Total	56,465	28,196	73,000	398,575

Note.

1/ use T&D total EPMC method for distribution and transmission revenue allocation.

2/ use SAP allocation method except for CARE program costs which are allocated on an equal cents per kWh basis.

(END OF APPENDIX C)

APPENDIX D
TABLE I

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC UNBUNDLING

SUMMARY OF 1998 DISTRIBUTION REVENUE REQUIREMENTS
(Millions of Dollars)

Line No.		Distribution
1	Retail Sales Revenue	2,003
2	Other Operating Revenue	28
3	Preliminary Total CPUC	2,031
4	Itemize nuclear decommissioning	
5	ICIP update as per D97-05-088	
		2,031
	ADJUSTMENTS:	
6	A&G & common and general: fixed Costs	(49)
7	Hazardous Substance Cleanup	(0.1)
8	ICIP	
9		1,982
10	Distribution Revenue Requirement w/o Other operating revenue	1,954

APPENDIX D
TABLE II

PG&E's 1998 net revenue allocation

Line No.	Class/Schedule	VOLT	Revenues at 1/1/96 Rates	1998 Adopted Annual Sales	Transmission Revenues	Public Purpose Revenues	Distribution Revenues	Nuclear Decommissioning Revenues	0.024 Estimated FX Revenue	Remaining Revenues	Annual Total Revenues (H)
					Illustrative						
	RESIDENTIAL:										
1	E-1/EL-1	S	2,924,392,560	24,063,296,772	128,558,241	100,215,497	847,283,535	12,432,533	577,519,123	1,258,383,630	2,924,392,560
2	E-7	S	135,862,408	1,321,875,009	5,350,102	4,770,915	40,485,661	577,595	31,725,000	52,953,135	135,862,408
3	E-8/EL-8	S	112,753,044	1,085,932,474	4,437,132	3,936,049	29,385,447	479,349	26,062,379	48,452,687	112,753,044
4	TOTAL RES		3,173,008,011	26,471,104,256	138,345,475	108,922,461	917,154,644	13,489,478	635,306,502	1,359,789,452	3,173,008,011
	SMALL L&P										
5	A-1	S	717,231,799	5,347,958,957	35,197,975	24,520,034	219,860,579	3,049,183	128,351,015	308,253,013	717,231,799
6	A-6	S	191,996,343	1,914,766,671	5,109,045	6,761,197	36,478,818	816,238	45,954,400	96,876,643	191,996,343
	Total A-1 /A-6					0	0		0	0	
7	A-15	S	404,221	1,432,353	29,502	13,173	279,716	1,718	34,376	45,735	404,221
8	TC-1	S	14,810,379	136,261,498	863,309	461,203	5,717,369	62,964	3,270,276	4,435,258	14,810,379
9	TOTAL SMALL L&P		924,442,742	7,400,419,479	39,199,831	31,755,608	262,336,483	3,930,103	177,610,068	409,610,649	924,442,742
	MEDIUM L&P										
10	Total A-10	P	8,788,493	91,082,444	234,572	310,892	1,553,618	37,363	2,185,979	4,466,069	8,788,493
11	Total A-10	S	1,102,365,155	10,925,884,748	38,082,175	38,792,299	252,207,770	4,686,509	262,221,234	506,375,167	1,102,365,155
12	TOTAL MEDIUM		1,111,153,647	11,016,967,192	38,316,747	39,103,192	253,761,388	4,723,872	264,407,213	510,841,236	1,111,153,647
	E-19 CLASS										
13	E-19 FIRM	T	352,620	4,124,135	10,428	12,666	69,064	1,499	98,979	159,984	352,620
14	E-19 V	T	470,351	5,641,872	27,019	16,952	176,872	2,000	135,405	112,103	470,351
15	Nonfirm	T	123,482	1,689,032	8,994	4,535	43,671	525	40,537	25,220	123,482
16	Total E-19	T	946,453	11,455,039	46,442	34,153	289,606	4,024	274,921	297,306	946,453
17	E-19 FIRM	P	36,080,868	454,297,467	793,339	1,309,193	5,257,898	153,391	10,903,139	17,663,908	36,080,868
18	E-19 V	P	9,054,189	117,836,597	185,315	330,098	1,235,182	38,492	2,828,078	4,437,024	9,054,189
19	Nonfirm	P	4,439,303	70,969,098	119,925	167,239	829,258	18,873	1,703,258	1,600,750	4,439,303
20	Total E-19	P	49,574,361	643,103,162	1,098,580	1,806,529	7,322,338	210,757	15,434,476	23,701,682	49,574,361
21	E-19 FIRM	S	331,551,496	3,572,771,835	10,884,876	11,784,441	72,093,642	1,409,532	85,746,524	149,632,480	331,551,496
22	E-19 V	S	511,068,147	5,870,354,327	14,937,138	18,313,423	99,604,050	2,172,715	140,888,504	235,152,317	511,068,147
23	Nonfirm	S	2,866,778	35,890,266	110,042	103,937	756,730	12,188	861,366	1,022,515	2,866,778
24	Total E-19	S	845,486,421	9,479,016,428	25,932,056	30,201,800	172,454,423	3,594,435	227,496,394	385,807,312	845,486,421
25	Total E-19		896,007,234	10,133,574,629	27,077,078	32,042,482	180,066,367	3,809,215	243,205,791	409,806,301	896,007,234
26	A-RTP-19	S	4,007,543	49,467,432	106,218	145,008	749,642	17,037	1,187,218	1,802,420	4,007,543
27	TTL A-RTP-19		4,007,543	49,467,432	106,218	145,008	749,642	17,037	1,187,218	1,802,420	4,007,543

APPENDIX D
TABLE II

Line No.	Class/Schedule	VOLT	Revenues at 1/1/96 Rates	1996 Adopted Annual Sales	Transmission Revenues	Public Purpose Revenues	Distribution Revenues	Nuclear Decommissioning Revenues	0.024 Estimated PX Revenue	Remaining Revenues	Annual Total Revenues [H]
					Illustrative						
28	Subtotal E-19	T	946,453	11,455,039	46,442	34,153	289,606	4,024	274,921	297,306	946,453
29	Subtotal E-19	P	49,574,361	643,103,162	1,098,580	1,806,529	7,322,338	210,757	15,434,476	23,701,682	49,574,361
30	Subtotal E-19	S	849,493,964	9,528,483,860	26,038,274	30,346,809	173,204,064	3,611,472	228,683,613	387,609,732	849,493,964
31	E-19 Class		900,014,778	10,183,042,061	27,183,296	32,187,491	180,816,009	3,826,252	244,393,009	411,608,720	900,014,778
32	STREETLIGHTS	S	42,451,584	330,315,569	872,310	1,327,833	24,758,017	180,475	7,932,374	7,380,575	42,451,584
	STANDBY										
	Small	T		7,050,081				0			
		P		2,202,592				0			
		S		550,706							
	Total <500 kW			9,803,379							
	Large	T		216,773,737							
		P		7,034,632			0				
		S		3,831,231			0				
	Total > 500kW			227,639,600			0				
				0							
33		T	17,194,526	223,823,818	660,554	626,896	4,360,265	73,099	5,371,772	6,101,940	17,194,526
34		P	2,282,796	9,237,224	187,322	74,862	1,243,972	9,705	221,693	545,242	2,282,796
35		S	550,611	4,381,937	31,934	18,937	212,946	2,341	105,166	179,287	550,611
										0	
36	TOTAL STANDBY		20,027,933	237,442,979	879,811	720,694	5,817,183	85,145	5,698,631	6,826,469	20,027,933
37	AGR AG-1 A	S	41,235,884	200,089,520	2,714,987	1,365,860	17,980,331	173,307	4,802,148	14,197,251	41,235,884
38	AG-RA	S	5,174,380	36,076,838	272,904	175,873	1,807,340	21,998	865,844	2,030,421	5,174,380
39	AG-VA	S	5,608,983	39,759,154	288,320	190,911	2,174,755	23,846	954,220	1,976,931	5,608,983
40	AG-4A	S	21,339,084	156,183,645	1,118,161	728,324	8,419,567	90,719	3,748,407	7,233,907	21,339,084
41	AG-5A	S	10,529,727	96,012,819	503,382	367,130	3,597,565	44,765	2,304,308	3,712,577	10,529,727
42	Total AG-1B		45,728,692	289,102,177	2,502,058	1,542,137	16,570,186	194,407	6,938,452	17,981,452	45,728,692
43	AG-RB	S	4,159,124	30,760,881	187,797	142,086	1,305,198	17,682	738,261	1,768,100	4,159,124
44	AG-VB	S	2,841,612	22,003,033	131,495	97,479	912,136	12,081	528,073	1,160,348	2,841,612
45	Total AG-4B		55,009,360	451,738,587	2,473,439	1,897,591	17,004,710	233,862	10,841,726	22,558,032	55,009,360
46	AG-4C	S	5,014,267	37,378,327	269,708	171,419	1,927,013	21,317	897,080	1,727,729	5,014,267
47	Total AG-5B		197,845,444	2,275,900,908	8,975,464	7,090,892	60,190,887	841,105	54,621,622	66,125,475	197,845,444
48	AG-5C	S	9,123,540	108,459,111	433,230	328,426	2,900,690	38,787	2,603,019	2,819,389	9,123,540
						0					
49	Total AGRA		83,888,057	528,121,976	4,897,754	2,828,098	34,242,840	356,635	12,674,927	28,887,804	83,888,057
50	Total AGRB		319,722,039	3,215,343,024	14,973,191	11,270,029	100,810,819	1,359,241	77,168,233	114,140,526	319,722,039
51	TOTAL AGR		403,610,096	3,743,465,000	19,870,945	14,098,126	135,053,659	1,715,876	89,843,160	143,028,330	403,610,096
	E-20 CLASS										
52	E-20 FIRM	T	165,455,309	2,966,568,953	2,291,087	6,364,435	7,723,079	703,404	71,197,655	77,175,649	165,455,309
53	E-20 Nonfirm	T	125,271,965	3,319,724,729	1,468,553	5,257,394	8,642,475	532,571	79,673,393	29,697,578	125,271,965
54	TOTAL	T	290,727,274	6,286,293,683	3,759,640	11,621,829	16,365,554	1,235,975	150,871,048	106,873,227	290,727,274
55	E-20 FIRM	P	371,377,595	5,298,177,526	8,693,823	13,729,605	57,621,854	1,578,846	127,156,261	162,597,207	371,377,595
56	E-20 Nonfirm	P	72,099,953	1,227,880,067	1,993,774	2,746,913	13,440,052	306,520	29,469,122	24,143,571	72,099,953
57	TOTAL	P	443,477,547	6,526,057,594	10,687,597	16,476,518	71,061,906	1,885,366	156,625,382	186,740,778	443,477,547

APPENDIX D
TABLE II

Line No.	Class/Schedule	VOLT	Revenues at 1/1/96 Rates	1998 Adopted Annual Sales	Transmission Revenues	Public Purpose Revenues	Distribution Revenues	Nuclear Decommissioning Revenues	0.024 Estimated FX Revenue	Remaining Revenues	Annual Total Revenues [H]
					Illustrative						
58	E-20 FIRM	S	296,443,892	3,535,661,338	11,350,336	10,676,008	75,180,222	1,260,278	84,855,872	113,121,175	296,443,892
59	E-20 Nonfirm	S	13,737,799	188,264,885	603,193	504,723	4,057,599	58,404	4,518,357	3,995,523	13,737,799
60	TOTAL	S	310,181,691	3,723,926,222	11,953,529	11,180,731	79,237,821	1,318,682	89,374,229	117,116,698	310,181,691
61	E-20 w/o RTP		1,044,386,513	16,536,277,499	26,400,767	39,279,079	166,665,281	4,440,023	396,870,660	410,730,703	1,044,386,513
62	A-RTP-20	T	6,788,792	72,999,996	112,590	241,233	723,787	28,861	1,752,000	3,930,320	6,788,792
63		S	27,461,757	331,642,044	666,686	990,675	4,496,887	116,749	7,959,409	13,231,351	27,461,757
64	Total A-RTP-20		34,250,549	404,642,040	779,277	1,231,908	5,220,675	145,610	9,711,409	17,161,671	34,250,549
65	Class w/o CONS	T	297,516,066	6,359,293,679	3,872,230	11,863,062	17,089,341	1,264,836	152,623,048	110,803,547	297,516,066
66		P	443,477,547	6,526,057,594	10,687,597	16,476,518	71,061,906	1,885,366	156,625,382	186,740,778	443,477,547
67		S	337,643,449	4,055,568,266	12,620,216	12,171,406	83,734,709	1,435,431	97,333,638	130,348,049	337,643,449
68	Class w/o CONS		1,078,637,062	16,940,919,539	27,180,043	40,510,987	171,885,956	4,585,633	406,582,069	427,892,374	1,078,637,062
69	Contracts	T	38,236,436	789,629,303	265,232	1,190,704	1,756,533	162,555	18,951,103	15,910,309	38,236,436
70		P	0	0	0	0	0	0	0	0	0
71		S	1,790,005	29,829,750	92,960	55,742	615,639	7,610	715,914	302,141	1,790,005
72	Total Contracts		40,026,441	819,459,053	358,192	1,246,445	2,372,172	170,165	19,667,017	16,212,450	40,026,441
73	E-20 w/ CONS	T	335,752,502	7,148,922,982	4,137,463	13,053,766	18,845,874	1,427,392	171,574,152	126,713,856	335,752,502
74		P	443,477,547	6,526,057,594	10,687,597	16,476,518	71,061,906	1,885,366	156,625,382	186,740,778	443,477,547
75		S	339,433,454	4,085,398,016	12,713,176	12,227,148	84,350,347	1,443,041	98,049,552	130,650,190	339,433,454
76	E-20 w/ CONS		1,118,663,504	17,760,378,592	27,538,235	41,757,432	174,258,128	4,755,798	426,249,086	444,104,824	1,118,663,504
77	SYSTEM - Core		7,653,345,853	76,323,876,075	291,848,458	268,626,391	1,951,583,338	32,536,835	1,831,773,026	3,276,977,805	7,653,345,853
78	SYSTEM		7,693,372,295	77,143,335,128	292,206,650	269,872,837	1,953,955,510	32,707,000	1,851,440,043	3,293,190,255	7,693,372,295

1 This table shows net revenues. Net revenues include non-allocated revenue adjustments from (a) optional TOU meter charges, (b) Streetlighting and Railway facility charges, (c) negotiated contracts, (d) standby charges, (e) load management, UCB, and nonfirm service discounts, (f) power factor revenues, (g) CCSF Hetch Hetchy Credits, (h) Residential A/C load control credit and master meter discounts, (i) CARE surcharge revenues, and (j) unconventional generation credits.

2 Streetlight revenues at present rates reflect PG&E's Phase II adopted 1993 streetlight facilities charges with no 1994 phase-in.

3 E-20 revenue on this table reflects the Economic Stimulus Rate discount.

4 The revenues shown on this table do not reflect a 10 percent discount to residential and small commercial customers or the costs associated with the Rate Reduction Bonds.

(END OF APPENDIX D)

A. 96-12-009
D. 97-08-056

COMMISSIONER JESSIE J. KNIGHT, JR. CONCURRING:

I support this decision, but feel compelled to memorialize thoughts that may aid future commission deliberation in dealing with new unbundling issues that will surely arise over time. The decision here provides a fair allocation of costs among the classic functional areas of transmission, generation and distribution, as well as an economically efficient means of calculating the competition transition charge (CTC). Yet, I must express concerns that the premise driving this stage of unbundling has a basic flaw. The exercise to divide the electric industry into three distinct functional components is an idea that no longer fits the reality of the evolving competitive market for electricity. Traditionally, the electricity industry has been segmented into three primary functions -- transmission, distribution and generation.

This decision reflects our own institutional biases that were cultivated during the several stages of our own initial procedural and issue development in the electrical restructuring proceeding, as well as the strictures evident in AB 1890 that serve as the intellectual and legislative anchors justifying the attempt to put costs into these three baskets. The study and debate over the course of this decision has highlighted the unequivocal fact that there are many costs that did not fit easily into one basket or the other.

Generally, these costs should be characterized as "retailing costs". These retailing costs can be categorized as reflecting the cost of selling electricity to an end-user. They are not costs associated with the generation of electricity. Fundamentally, the production of power, the actual generation of electricity, is a wholesale function rather than a retail function. These retailing costs are not a true component of the cost of distribution, because the business function of selling a product to a customer is inherently not a distribution cost. By definition, transmission costs are not associated with providing retail service.

The procedural necessity in place currently, that insists that all costs must be allocated to generation, transmission, or distribution, has obscured the issues in this proceeding. There are identifiable costs associated with the provision of retail electric service, costs that should be unbundled from wholesale costs, recovered through the provision of retail service and therefore solely collected from retail customers of the utility.

As a result of this decision, some of these retailing costs have been allocated to generation and some assigned to distribution. Of paramount concern is the fear that recovery of retailing costs in distribution rates will require competitive retail providers to inadvertently pay the retailing costs of the utilities. Realization of this envisioned circumstance would create a subsidization of the utility's retailing function, thus promoting injury to the development of a competitive retail electric marketplace.

As the Commission proceeds to fashion a robust and competitive retail market, it must actively seek to further unbundle these "retailing costs" from distribution and generation rates. Only this proactive effort can ensure a level playing field between the utilities and competitive energy service providers.

The Commission's experience in overseeing the natural gas and the telecommunications industries prepares us for the inevitable fact that the unbundling that is occurring here will be the first of many such proceedings, as our thinking and analysis mature. It is a historic fact that the telecommunications industry has undergone many rounds of unbundling. First, customer-premise-equipment was unbundled from telephony. Later, long distance was unbundled from the local service market, as a result of the disaggregation of AT&T that resulted from the Modified Final Judgement in 1984. Since then, central office space has been unbundled, as was the many underlying basic service elements in the 1980's and early 1990's, as part of the federal open network architecture policy. Currently, local telephone service is being further unbundled with links being unbundled from ports. In fact, the entire network is being unbundled into basic network functions, with each getting unbundled from each other. Furthermore, in the wholesale provision of bundled service, the Commission has seen fit to ensure that wholesale rates are discounted to unbundle retailing costs.

In the natural gas industry, the merchant function, gas gathering, and interstate transport are all unbundled. In a Commission decision that is a mere few weeks old, gas storage was unbundled. Moreover, this Commission is actively engaged in bringing about even greater unbundling in the intrastate gas arena as a result of D.97-08-055. Furthermore, it is the intention of the Commission to ensure that its forthcoming long term gas strategy also addresses this issue of unbundling retailing costs from the provision of wholesale services.

In the electricity industry, as we explored the various aspects of the industry, it became apparent that generation is made up of many severable components. Electricity has an energy component, reliability components, and retailing components. Distribution has revenue cycle components with distinct retailing elements. Even the overall revenue cycle of the utility can be further unbundled into meter reading, billing, and other severable parts. It is not beyond the pale for the Commission to potentially find that many more underlying functions may eventually be unbundled one from another as a result of federal policies that will certainly emerge and evolve over time.

The process of unbundling can be likened to the peeling of an onion. Under each layer, there is another layer that can be peeled away, or further unbundled, if you will. The Commission should fully expect and more importantly, **seek** the further unbundling of distribution functions to assure that retailing costs are truly unbundled from distribution. Only this strategy will yield a competitive market such that future retailers will be able to compete on a level playing field with the utility distribution companies. In short, the development of a competitive retail market **requires** the unbundling of retail costs from wholesale services and the sole recovery of these costs from utility retail customers.

Dated August 1, 1997 in San Francisco, California.

/s/ Jessie J. Knight, Jr.
Jessie J. Knight, Jr.
Commissioner