ALJ/ANG/sid **Mailed 9/23/99**

Decision 99-09-064 September 16, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Pacific Gas and Electric Company, to establish the eligibility and seek recovery of certain electric industry restructuring implementation costs as provided for in Public Utilities Code Section 376.	Application 98-05-004 (Filed May 1, 1998)
San Diego Gas & Electric Company, for (1) a determination of eligibility for recovery under Public Utilities Code Section 376 of certain cost categories and activities, (2) a finding of reasonableness of the costs incurred through 12/31/97, (3) approval of an audit methodology for verifying the eligibility of Section 376 costs for recovery from 1998 through 2001, and (4) approval of a section 376 balancing account mechanism to recover eligible costs.	Application 98-05-006 (Filed May 1, 1998)
Southern California Edison Company, to address restructuring implementation costs pursuant to Public Utilities Code Section 376, in compliance with Ordering Paragraph 18 of D.97-11-074.	Application 98-05-015 (Filed May 1, 1998)

(See D.99-05-031 for a list of appearances.)

TABLE OF CONTENTS

Title **Page**

FINAL OPINION REGARDING PUBLIC UTILITIES CODE SECTION 376 AS APPLIED TO SOUTHERN CALIFORNIA EDISON COMPANY 2
Summary 2
Procedural History 2
Framework for Considering § 376 Treatment 6
Proposed Settlement 7
Enron's Position 12
Discussion 14
Implementation of the New Market Structure has Occurred as of December 31, 1998 16
Restructuring-Related Costs are Recoverable 18
Only Incremental Costs May Receive § 376 Treatment 19
Avoided Costs and Associated Cost Savings Must Be Considered in Approving Reasonableness of Costs 19
Costs Will Not Be Given § 376 Treatment if it is Determined That Those Costs Will Be Recovered From Customers in Another Way 19
Costs Categorized as Eligible for § 376 Treatment Benefit All Customers and Must Be Paid for by All Customers 20
Eligible Costs Should Be Recovered Through the TRA or Similar Ratemaking Mechanism 22
Adopted Guidelines 23
Proposed Settlement and Conformance with Adopted Guidelines 24
The IMC Costs Recommended for § 376 Treatment in the Proposed Settlement Comports with our Guidelines; the Proposed Cost Recovery of IMCs Also Complies with Those Guidelines 27
Comments on Proposed Decision 30
Findings of Fact 31
Conclusions of Law 35
FINAL ORDER 38

ATTACHMENT 1 – Settlement Agreement

FINAL OPINION REGARDING PUBLIC UTILITIES CODE SECTION 376 AS APPLIED TO SOUTHERN CALIFORNIA EDISON COMPANY

Summary

In this decision, we consider the settlement proposal presented to us by Southern California Edison Company (Edison) regarding issues related to restructuring implementation costs to which Pub. Util. Code § 376[1] treatment applies. The settling parties joining Edison in this motion are the Office of Ratepayer Advocates (ORA), California Association of Cogenerators (CAC), California Farm Bureau Federation (Farm Bureau), California Industrial Users (CIU), California Large Energy Consumers Association (CLECA), California Manufacturers Association (CMA), Energy Producers and Users Coalition (EPUC), The Utility Reform Network (TURN), University of California, and California State University.

With the addition of one modification, we approve the settlement as being reasonable in light of the whole record, consistent with the law, and in the public interest. We clarify that restructuring implementation costs that are not given § 376 treatment must be recovered prior to the end of the rate freeze. We approved similar settlements for Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) in Decision (D.) 99-05-031.

Procedural History

In D.97-11-074, we ordered Edison, PG&E, and SDG&E to file applications to identify restructuring implementation costs incurred under § 376. On May 1,

[1] All statutory references are to the Pub. Util. Code, unless otherwise noted.

1998, PG&E, SDG&E, and Edison filed Application (A.) 98-05-004, A.98-05-006, and A.98-05-015, respectively, to identify such costs.[2] Protests were filed by ORA; Enron; jointly by CAC and EPUC; jointly by CMA, CLECA, and CIU. PG&E, Edison, and SDG&E replied to these protests. PG&E, Edison, ORA, Enron, and TURN filed prehearing conference statements.

On January 1, 1998, Senate Bill (SB) 960 became effective. SB 960 established various procedures for our proceedings. These rules are set forth in §§ 1701, *et seq.* and Article 2.5 of our Rules of Practice and Procedure. In accordance with the SB 960 rules, this proceeding has been categorized as ratesetting (Resolution ALJ 176-2993, as noticed in the Daily Calendar of May 26, 1998).

The first prehearing conference in this proceeding was held on June 25, 1998. On July 10, Commissioner Bilas issued a scoping memo that designated Administrative Law Judge (ALJ) Minkin as the principal hearing officer and set forth the issues to be included in this proceeding. The scoping memo established a procedural schedule under which the Commission would resolve Phase 1 issues by April 30, 1999, and would conclude these proceedings no later than 18 months from the date of filing of the application, pursuant to SB 960, Section 13.

---

[2] D.97-11-074 ordered the utilities to file these applications by March 31, 1998. This date was extended to May 1, 1998 by authorization of the Executive Director on March 25, 1998.

The Assigned Commissioner's Ruling (ACR) established the scope of this proceeding:

> "In Phase 1, the Commission must determine which programs are necessary to accommodate implementation of direct access, the Independent System Operator (ISO), and the Power Exchange (PX) and thus which costs are potentially eligible for § 376 treatment. Phase 1 will look closely at defining implementation and will focus particularly on cost categorization, i.e., whether the costs claimed should be categorized as costs of implementing electric restructuring and should receive § 376 treatment or whether these expenditures should be categorized as distribution costs, the costs of competing in the new market, or some other cost category, and how cost recovery should occur. In defining implementation, it will be helpful to consider the range of estimates the utilities have provided for 1998 through 2001. While Phase 1 will not review these estimates or adopt any particular dollar figure associated with these forecasts, such estimates will be helpful in understanding the programs the utilities believe are necessary to implement direct access, the ISO, and the PX."

As directed by the ACR, several parties to this proceeding attended a meet and confer session on August 11 and filed a joint case management statement on August 24. At the request of parties, the scoping memo was amended to revise the procedural schedule to allow more time to prepare testimony and rebuttal and to delay the beginning of evidentiary hearings. A second prehearing conference was held on October 8, 1998. ORA submitted testimony on August 31. TURN, Enron, CLECA and CMA (jointly), and CAC and EPUC (jointly) submitted testimony on September 14. Edison, PG&E, SDG&E, ORA and TURN submitted rebuttal testimony on October 5.

Edison's Phase 1 issues were addressed in seven days of evidentiary hearings held from October 21 through November 3, 1998. Commissioner Bilas was in attendance for opening statements on October 21 and closing arguments on November 3. Phase 1 of Edison's application was submitted upon reply briefs, filed on December 15, 1998. Edison, ORA, CLECA/CMA, CIU, CAC/EPUC, TURN/UCAN, Enron, and Farm Bureau filed opening briefs. Edison, ORA, CLECA/CMA, CIU, Enron, and Farm Bureau filed reply briefs. The principal hearing officer completed and issued the proposed decision on March 11, 1999, 86 days after submission. Commissioner Bilas issued an alternate decision on the same date. After considering comments on the proposed decision, ALJ Minkin mailed a revised proposed decision to parties on April 23.

On May 5, 1999, Edison and ORA jointly filed a motion to set aside submission of A.98-05-015, in order to allow the Commission to consider an anticipated settlement. Enron timely filed a response opposing this motion. On May 18, Edison filed a Joint Motion for Adoption of Settlement. The settling parties joining Edison in this motion are ORA, CAC, Farm Bureau, CIU, CLECA, CMA, EPUC, TURN, University of California, and California State University.

Edison explains that it has been exploring settlement options since June 1998, when the first prehearing conference in these proceedings was convened, in response to Commissioner Bilas' encouragement to explore these possibilities. Edison explicitly recognizes that parties resumed settlement discussions only after the "added perspective" of two versions of the proposed decision and alternate decisions from two Commissioners, as well as hearing the various perspectives of parties in several all-party meetings.[3] On May 5, Edison and

---

[3] Restructuring implementation costs for PG&E and SDG&E were considered in D.99-05-031, issued on May 13, 1999. A proposed decision, a revised decision, and two alternate decisions were issued regarding these costs.

ORA jointly noticed a settlement conference for May 12, and included a draft of the settlement agreement with that notice. Representatives of CLECA, Enron, ORA, PG&E, TURN, SDG&E, and Edison attended the settlement conference.

The assigned Commissioner and ALJ jointly granted the motion to set aside submission of this proceeding and shortened the period for commenting on the proposed settlement. We affirm that ruling today. Commissioner Bilas has encouraged settlement in these contentious proceedings from the beginning. While we would have preferred to have a settlement submitted prior to the issuance of a proposed decision, as contemplated in Rule 51.2, we are satisfied that setting aside submission to consider the settlement is within our discretion, particularly because the proposed settlement resolves Phase 2 issues, as well.

Enron timely filed comments on the proposed settlement on June 1. The settling parties filed reply comments on June 8.

Framework for Considering § 376 Treatment

Section 376 provides, as follows:

> "To the extent that the costs of programs to accommodate implementation of direct access, the Power Exchange, and the Independent System Operator, that have been funded by an electrical corporation, and have been found by the commission or the Federal Energy Regulatory Commission to be recoverable from the utility's customers, reduce an electrical corporation's opportunity to recover its utility generation-related plant and regulatory assets by the end of the year 2001, the electrical corporation may recover unrecovered utility generation-related plant and regulatory assets after December 31, 2001, in an amount equal to the utility's cost of commission-approved or Federal Energy Regulatory Commission approved restructuring-related implementation programs. An electrical corporation's ability to collect the amounts from retail customers after the year 2001 shall be reduced to the extent the Independent System Operator or the Power Exchange reimburses the electrical corporation for the costs of these programs."

Because the costs of establishing the infrastructure underlying the new market structure were not included in rates as of June 10, 1996, the Legislature provided an opportunity for the utilities to be made whole in terms of transition cost recovery. This important concept was discussed in D.97-12-042, in which we articulated the extended nature of transition cost recovery, to the extent such costs are displaced because of recovery of approved restructuring implementation costs.

> "As an initial matter, it is important to understand that § 376 does not directly authorize recovery of [Power Exchange] PX and [Independent System Operator] ISO implementation costs. [footnote omitted.] Rather, it extends the period for recovery of "generation-related plant and regulatory assets" [footnote omitted] to the extent that the opportunity to recover them has been reduced by the collection of specified implementation costs. Thus, § 376 by itself does not authorize recovery of any costs; rather, it permits utilities to recover uneconomic generation-related costs (*see* § 367) beyond the December 31, 2001 deadline set in § 367(a), to the extent the opportunity to recover these costs is reduced by [Federal Energy Regulatory Commission] FERC- or Commission-authorized recovery of unreimbursed implementation costs incurred by the utilities." (D.97-12-042, mimeo., at p. 4.)

Proposed Settlement

Edison and the settling parties ask that we approve a proposed settlement that resolves the issues in both Phase 1 and Phase 2 of this proceeding. The proposed settlement addresses recovery of 1997 and 1998 restructuring implementation costs as well as the maximum amount that Edison can claim for § 376 treatment related to certain costs, i.e., amounts that might lead to an extension of transition cost recovery after the rate freeze ends. Thus, the proposed settlement resolves all issues identified in the Scoping Memo, as well as the reasonableness of dollar amounts Edison has or will expend on restructuring implementation activities for the period 1997 – 2001.

Under the proposed settlement, costs would be separated into two major categories. Externally managed restructuring costs (EMCs) consist of FERC-approved actual amounts for the PX Initial Charge, the start-up and development portion of the ISO Grid Management Charge, and Commission-approved Consumer Education Program costs, Electric Education Trust, costs, and related customer education costs. Internally managed restructuring costs (IMCs) consist primarily of the costs of direct access implementation and demand PX bidding and settlement systems, and consist specifically of the following Industry Restructuring Memorandum Account (IRMA) subaccounts: Direct Access Implementation Costs, Hourly Interval Meter Installation and Reading Costs, Billing Modification Costs, Customer Information Release Systems Costs, and Utility Energy Supply Forecast. In addition, costs associated with the Universal Node Identifier System (UNIS) are considered to be internally managed costs.

The settlement addresses both eligibility for § 376 treatment and cost recovery. The settlement proposes that the externally managed costs be recovered on a dollar-for-dollar basis, based on actual amounts including payments or credits, or other amounts billed or assigned to Edison, whether these amounts exceed or are less than those estimated. Edison will track its EMCs through the earlier of the date Edison is determined to have recovered its transition costs or through December 31, 2001. The parties agree that Edison should recover the revenue requirement associated with actual expenditures on IMCs, capped at $160 million. In the event that Edison spends less than $160 million on IMCs, ratepayers would be responsible only for those actual amounts incurred. Of the $160 million in capped IMCs, $58.593 million of that amount is eligible for 376 treatment. Thus, the amounts that are eligible for § 376 treatment, i.e., could displace transition cost recovery, are the actual EMCs and $58.593 of the IMCs. Edison forecasts EMCs of $151.407 million; therefore, the anticipated total of costs eligible for § 376 treatment is $210 million.

The proposed settlement also identifies Other Industry Restructuring Costs as Power System Control Modifications, Meter Certification, Electric Supply Settlement System, Generation ISO/PX Settlement, Billing, and Bidding systems, and Western Power Exchange Project. Parties agree that costs associated with these functions will be treated as generation going forward costs. Therefore, these costs would not be treated as transition costs, but as costs of operating in the market. Specifically, these costs will be allocated to generation plants based on plant output during the first quarter of 1999. If a plant is market valued, the costs allocated to that plant would be reallocated to the remaining plants of that particular fuel type.

Edison agrees not to seek transition cost recovery under § 375 for any new or existing employee performing activities described in A.98-05-015. This agreement does not affect Edison's existing request for recovery of specified employee-related transition costs in the Annual Transition Cost Proceeding (A.98-09-008).

Finally, the proposed settlement defines Substantial Future Regulatorily Required Restructuring Costs as costs for new restructuring-related programs that represents a substantial departure from the current restructuring-related programs. The settlement provides for a process by which such unanticipated costs may be recovered by application or advice letter, if all signatory parties agree that the program is substantial and if Edison makes a good faith effort to resolve issues. Parties need not agree on the resolution of such issues and may support or oppose such a filing before FERC or this Commission. However, parties agree that such costs will not be eligible for § 376 treatment. The parties define "substantial" in this context as programs required by a FERC or

Commission decision that imposes costs of $2.0 million or greater in revenue requirement prior to January 1, 2002, for a single restructuring-related, direct access, ISO, or PX program.

During the rate freeze period, the settling parties propose that the externally managed costs and the internally managed costs be recovered through the Transition Revenue Account (TRA). Once the rate freeze ends and the TRA is eliminated, the revenue requirement associated with these costs will be recovered through a rate component adopted in Edison's post-transition ratemaking application (A.99-01-016 *et al.*). After the Commission adopts such a methodology, Edison will file an annual advice letter to establish the rate to recover the IMC and EMC revenue requirement. Except for this advice letter, neither the reasonableness of IMC or EMC costs nor the cost recovery mechanism requires any further filing or request by Edison or any approval by this Commission.

Edison will enter the total amount of EMCs and § 376 IMCs in a new account, the "CTC Displacement Tracking Account." Edison will then compare the total amount entered in this account to its Transition Cost Balancing Account (TCBA). At the end of the transition period, if the TCBA reflects an undercollection that is less than or equal to the amount recorded in the CTC Displacement Tracking Account, then Edison would be entitled to recover the TCBA undercollection after the transition period. If the TCBA reflects an undercollection of transition costs greater than the amounts recorded in the CTC Displacement Tracking Account, Edison would recover the amount in the CTC Displacement Tracking Account.

Finally, the parties agree that internally developed software can be expensed for tax purposes, but that the tax treatment of other computer software and capital assets must be capitalized. Edison has identified $10 million of other assets that must be capitalized for tax purposes, regardless of ratemaking treatment. Parties agree that these costs will be expensed in computing regulatory book expense, but capitalized and depreciated in computing regulatory tax expense. Deferred taxes will be computed on all book-tax differences caused by this treatment, which will earn a return at the reduced transition cost rate of return and will be included in the TRA. Additional expenditures or costs incurred after December 31, 1998, that are treated as expenses for ratemaking, but which must be capitalized for tax purposes, will receive the same treatment.

The parties contend that the settlement is in the public interest and reaches a fair compromise of the disputed issues in this proceeding. Edison had originally contended that all the programs described in its application should be approved for § 376 treatment, subject only to a voluntary cap of $275 million. ORA was primarily concerned with two issues: (1) Edison used an overly broad definition of implementation; and (2) the need for ongoing reasonableness review and the failure to examine costs before the fact could lead to insufficient utility effort to control such costs and would use disproportionate amounts of regulatory resources to review those costs.

In ORA's view, the proposed settlement and limit on § 376 eligibility satisfactorily resolves these issues. ORA contends that the potential of $210 million in § 376 eligible costs compares favorably to Edison's request to approve nearly $430 million in restructuring implementation costs, although ORA recognizes that these costs would be subject to the voluntary cap of $275 million. In addition, ORA is satisfied that an authorization to recover no more than $160 million of internally managed costs responds to ORA's concern over utility management control over such costs and regulatory process. Since Edison estimated approximately $279 million in IMCs, this represents a reduction of approximately $119 million. Furthermore, ORA believes that the requirement that Edison must seek approval for substantial future regulatorily required restructuring costs is fair. This requirement provides a limit to Edison's ability to seek any further costs, while at the same time providing Edison with a fair opportunity to seek recovery of such costs.

CLECA, CMA, CIU, EPUC, and CAC are satisfied that the proposed settlement limits the transition cost carryover effects of § 376 and furthers the goal of limiting charges to customers. Farm Bureau and TURN are satisfied that these costs are not included in distribution rates, nor will distribution rates be used as the vehicle for recovery of restructuring-related costs. UC and CSU are satisfied that the caps on § 376 eligibility and the recovery of IMCs are consistent with the balance of utility customer and shareholder interests reflected in AB 1890.

Enron's Position

Enron objects to the proposed settlement on both procedural and substantive grounds. Enron contends that this settlement must be viewed as contested and that we must review the settlement in terms of balancing the interests of stakeholders. Enron was not contacted when settlement discussions were re-initiated after the proposed decisions and alternates were released and was not invited to the meeting at which settlement principles were discussed. While Enron attended the settlement conference, Enron claims it was presented with a finished product. Enron is concerned that despite fully litigating the issues in Edison's case-in-chief, Enron was effectively excluded from the negotiation process.

Enron recommends that we reject the settlement, but if the settlement is approved, at a minimum, Enron recommends that we ensure functionalization is not precluded in other proceedings. Functionalization is the assignment of costs to particular services or functions. Enron believes that such cost assignment is necessary to facilitate continued restructuring efforts. Enron recommends that this approach would assist in the transition to competitive markets, prevent subsidization of utility-offered competitive and potentially competitive services by captive ratepayers, and ensure that alternate service providers have the ability to compete with the utilities in the provision of competitive services.

Enron contends that because the implementation costs are associated with the functions of distribution, transmission, generation, and procurement, the costs must be identified with the service for which they were incurred and recovered through that service. Enron asserts that Commission policy requires functionalization. In D.96-10-074, we ordered the UDCs to separate their most recent authorized rate base and revenue requirements into the functions of generation, transmission, and distribution. This was confirmed in D.97-08-056, in which we also ordered that costs be separated into nuclear decommissioning and public purpose programs.

Enron disputes Edison's recovery of approved settlement amounts through monthly debits to the TRA. This cost recovery mechanism recovers all settlement costs (including procurement costs) from all customers. Enron believes this recovery mechanism results in recovery of costs which runs counter to established policy favoring unbundling of costs for recovery in order to facilitate efficient markets and customer choice.

Certain issues regarding PX credits and long-run marginal costs of procurement were considered in the Revenue Adjustment Proceeding (RAP), A.98-07-006. In addition, the use of long-run marginal costs in determining UDC credits for customers who receive revenue cycle services from an alternate provider is an issue in A.99-03-019. At a minimum, Enron argues that we must ensure our actions in this decision do not preclude Edison from assigning cost responsibility for procurement costs.

Finally, Enron objects to the proposed treatment of Other Industry Restructuring Costs. The settlement proposes that these costs be treated as generation going forward costs. While Enron recognizes that such treatment would allocate costs to various plants, would record the costs in the applicable generation plant memorandum account, and thus be recovered through the wholesale market, Enron contends that such treatment is not appropriate. Enron argues that only Generation Settlement, billing, and bidding Systems costs relate to Edison's activities in the wholesale market; the other costs are associated either with procurement of energy for bundled service customers or with Edison's role as a transmission owner. Enron does not believe it is reasonable to allow Edison to recover costs from a market that does not receive any benefits from incurring such costs.

Discussion

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

In D.92-12-019, we set forth criteria by which we would consider an all-party settlement. The first criterion is that the settlement must enjoy "the unanimous sponsorship of all active parties to the instant proceeding." Certainly, this proposal is close to being an all-party settlement. Enron, however, opposes the adoption of the settlement. We agree with Enron that we must consider the settlement under the criteria set forth in Rule 51.1(e), rather than under the all-party settlement criteria. This is a more stringent standard of review, as we have recognized in previous decisions:

> "However, the standard of review here is somewhat more stringent. Here, we consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law."
> (D.96-01-011, 64 CPUC2d, 241, 267, citing D.94-04-088.)

With the addition of one modification, we believe that the settlement before us is reasonable in light of the whole record, consistent with the law, and in the public interest. We are also convinced that the settlement generally balances the various interests at stake. We recognize that Enron is the only competitor participating in this proceeding and that Enron objects to the settlement. Enron proposes that the settlement be rejected in part (or be required to be modified) in order to require functionalization of restructuring costs. We will not adopt Enron's proposal here; however, we will ensure that our treatment of cost recovery in this settlement does not preclude future cost assignments according to function, if this approach is adopted in other proceedings.

We discuss the specifics of the settlement in terms of principles related to our general guidelines regarding § 376 treatment and cost recovery.

Implementation of the New Market Structure has Occurred as of December 31, 1998

As we determined in D.99-05-031,[4] defining implementation for purposes of § 376 treatment is a pivotal determination in establishing our principles for cost eligibility. This determination has crucial ramifications for § 376 eligibility, and by extension, cost recovery and impacts on the competitive market.

As in D.99-05-031, we find that implementation of programs to accommodate direct access, the ISO, and the PX that are eligible for § 376 treatment are the reasonable and necessary costs incurred for such programs as of December 31, 1998. Section 376 does not define implementation and we cannot find that implementation necessarily lasts through December 31, 2001. AB 1890 does not prescribe the duration for implementation. Consequently, we shall define implementation based on our best judgment, the record in this proceeding, the period it may reasonably take to implement direct access.

The Legislature determined that there were certain costs to be expended on new programs to implement the PX, the ISO, and direct access. The Legislature afforded the utilities the opportunity to recover the costs of assets that might become uneconomic in the new competitive generation market by providing for a rate freeze and subsequent recovery of such transition costs during the transition period to the extent that recovery of implementation costs might delay transition cost recovery. It would be inequitable to require that these new programs be established and provide the opportunity for full transition cost recovery, without providing for some mechanism to ensure that

[4] While settlements do not set precedent, the policy discussion in A.99-05-031 is equally applicable here.

the costs of implementing the new programs do not interfere with transition cost recovery:

> "The Legislature was aware of the residual nature of the CTC and recognized that the size of the CTC would be affected by the levels of the other rate components. Because the total rate is frozen, the portion of the rate available to offset transition costs, the CTC, decreases as other components increase. The consequence of a lower CTC is a slower pace of recovery of the utilities' uneconomic costs.
>
> "Seen in this light, it becomes clear why the Legislature provided for special treatment for the 'costs of programs to accommodate implementation of direct access, the Power Exchange, and the Independent System Operator.' These are three new major programs that we created to carry out our plan for industry restructuring, described in our Preferred Policy Decision (D.95-12-063, as modified by D.96-01-009). The Commission required the utilities to bear actual or potential additional costs to implement these new programs. None of these additional costs were reflected in the frozen rates, and recovery of these costs during the transition period would necessarily displace other cost recovery. The residual nature of the CTC meant that recovery of these implementation costs jeopardized the Legislative plan for offsetting the utilities' uneconomic costs.
>
> "The solution codified in § 376 is to allow the utilities to recover the implementation costs they incur but in effect to extend the period for recovery of uneconomic costs to the extent necessary to restore the balance of risks of the initial concept of cost recovery. Utilities remain at risk for recovering their uneconomic costs during the transition period, but that risk is not increased by FERC- or Commission-authorized recovery of implementation costs." (D.97-12-042, mimeo., at p. 5.)

Therefore, only costs defined as reasonable and necessary for accommodating the implementation of the ISO, the PX, and direct access will receive § 376 treatment. However, reasonable costs related to certain restructuring activities may also be recovered from ratepayers, but will not receive § 376 treatment. Since many of these costs are incurred to comply with specific orders of this Commission, we will provide mechanisms for recovery, as we discuss below.

Restructuring-Related Costs are Recoverable

In D.99-05-031, we determined that costs incurred by PG&E or SDG&E that have been spent on approved restructuring-related activities should be recoverable from customers. While recognizing that settlements do not set precedent, we will adopt the same finding for Edison. Therefore, costs incurred by Edison to carry out many Commission-mandated restructuring related programs are also recoverable in rates. The Commission has issued several decisions that required the utilities to facilitate direct access. As a result, we will provide the utilities an opportunity to recover the reasonable costs of complying with Commission requirements. However, Edison may also be incurring costs to compete in the new competitive generation marketplace. These costs cannot be recovered through rates, but must be recovered through wholesale or retail markets, as appropriate. In addition, such restructuring-related costs incurred during the rate freeze period must be recovered prior to the end of the rate freeze. We do not anticipate that restructuring-related costs would be required after the rate freeze. By definition, the transition period is over and restructuring is implemented. The Commission may authorize other ongoing costs to be recovered in future proceedings. As we have stated in several decisions,[5] the rate freeze provided for in § 368(a) is a freeze and not a deferral. Although the costs

[5] See, e.g., D.97-10-057, D.97-11-074, D.98-03-059, and D.99-05-051.

for establishing direct access programs are not included in the rate levels frozen at the June 10, 1996 levels, we are approving a settlement that specifically does not grant § 376 treatment to these costs. Therefore, we clarify that recovery of restructuring-related costs incurred during the rate freeze cannot be deferred until the rate freeze is over, but must be recovered from headroom during the transition period. In other words, before the rate freeze ends, Edison must ensure that it recovers these costs through the TRA, which is the ratemaking approach proposed by the settlement.

Only Incremental Costs May Receive § 376 Treatment

All parties agree that costs eligible for § 376 treatment must be incremental to those costs covered in current rates. These costs must also be incremental to those costs that relate to ongoing utility business.

Avoided Costs and Associated Cost Savings Must Be Considered in Approving Reasonableness of Costs

Certain features of implementation may reduce costs for the utilities. It is reasonable to incorporate these avoided costs and any associated cost savings into a final determination of costs receiving § 376 treatment.

Costs Will Not Be Given § 376 Treatment if it is Determined That Those Costs Will Be Recovered From Customers in Another Way

Only those costs not recovered in any other way will receive § 376 treatment. To the extent such costs are recovered in FERC-approved rates, are reimbursed through the ISO and the PX, or are recovered directly from customers through fees, there is no need to allow such costs to also receive § 376 treatment.[6]

Costs Categorized as Eligible for § 376 Treatment Benefit All Customers and Must Be Paid for by All Customers

We have long held to the standard that the purchaser or user of a service should bear responsibility for those costs. We have consistently recognized the importance of providing accurate price signals, and pricing based on the principle of cost causation. (D.97-04-082 mimeo., at p. 123.) Similarly, all customers must pay for costs that benefit all customers. (D.97-12-112, mimeo., at p. 14.) We adopt these principles for costs receiving § 376 treatment. To the extent that all customers benefit from establishing the new market structure, all customers must pay. If only certain customers benefit from a particular service, those customers must bear responsibility for those costs.

As proposed by Enron, functionalization can be defined as cost assignment by service or program, which can be distinguished from cost allocation. Cost allocation assigns cost responsibility by customer group. Consistent with our determination in D.99-05-031, we do not believe further functionalization of restructuring implementation costs is necessary at this time. We recognize that restructuring implementation costs have been incurred to create the new market structure. In general, all customers, whether bundled or direct access, benefit from the creation of the new competitive regime and therefore, consistent with cost causation principles, must bear the burden of these costs. However, to the

[6] We will not address the issue of fees for Direct Access Service Request processing or fees for discretionary services. PG&E, Edison, and SDG&E have recently filed applications to address such fees.

extent that we intend to look at cost assignment of subsets of these costs in other proceedings, we will not preclude such a possibility. For example, in D.99-06-058, we stated our intention to require PG&E, Edison, and SDG&E to include in their respective 1999 revenue allocation proceeding applications a PX credit calculation that reflects certain long-run marginal costs of the PX credit. The utilities have filed applications to address fees for Direct Access Service Request processing and fees for discretionary services. In A.99-03-013 *et al.*, we are considering the use of long-run marginal costs in the determination of credits for customers who receive revenue cycle services from an alternative provider. As the settling parties acknowledge in reply comments, " . . . recovery of restructuring related costs through the Transition Revenue Account (TRA) would not preclude subsequent inclusion of some subset of those costs in the PX credit." (Reply comments, p. 5.) In fact, while cost recovery will occur through the TRA, the utilities must track with specificity all costs to be reflected in the PX credit.

Enron also objects to categorizing certain costs as going forward costs. Enron asserts that the Electric Supply Settlement System is used for procurement for bundled customers and that the costs for Power System Control Modifications, Meter Certification, and Western Power Exchange Projects are associated with Edison's role as a transmission owner. The settling parties maintain that while the supply settlement system costs may be used for procurement of energy, such costs should not be precluded from recovery as going forward costs, i.e., recovered from generation market revenues. The settling parties also explain that the other costs are not associated with Edison's role as a transmission owner, but arose from the development of the ISO and PX. The settling parties assert that all such costs do not necessarily require the same cost recovery mechanism as the EMCs or IMCs. In the give and take of the settlement process, parties have agreed that these costs should bear some market risk rather than being recovered through the TRA. We will not dispute this approach.

Eligible Costs Should Be Recovered Through the TRA or Similar Ratemaking Mechanism

D.97-12-042 allowed the utilities to establish a tracking account for costs deemed eligible for § 376 treatment.

> "When eligible costs are recovered (*i.e.*, when collected revenues are allocated to offset eligible costs), the affected utility should record the amount recovered in a tracking account. When we approach the end of the transition period, we will determine whether and to what extent collection of the CTC should be continued past December 31, 2001 to compensate for the reduced opportunity to recover uneconomic costs. [footnote omitted] Obviously, § 376 comes into play only if uneconomic costs are not fully recovered by December 31, 2001."

Edison's request to recover eligible costs in the TRA is reasonable. Given the guidelines adopted in this proceeding, there is no need to track IMCs beyond 1998 for § 376 treatment purposes. However, consistent with our previous discussion, such costs must be recovered prior to the end of the rate freeze.

We agree that Edison should track the § 376-eligible costs in a memorandum account to compare with transition cost recovery as we draw closer to the end of the rate freeze. We will develop a methodology to compare these costs and the necessity for extending CTC in A.99-01-016, *et al.*, the proceedings we have established to review post rate freeze ratemaking methodology.

Once final costs are approved for § 376 treatment, revenues should be allocated to these costs according to the principles established in D.99-06-058, unless that methodology is modified in a subsequent decision.

Adopted Guidelines

As stated in D.99-05-031, we provided general guidelines regarding § 376 treatment and cost recovery issues:

1. Identification and recovery of all restructuring implementation costs shall be addressed in this proceeding. Restructuring- related costs other than restructuring implementation costs, shall be recoverable from customers.

2. Only those costs expended to accommodate implementation of the ISO, PX, and direct access until December 31, 1998 shall receive § 376 treatment. Therefore, costs incurred after 1998 are not eligible for § 376 treatment and the costs of operating these programs on an ongoing basis are not eligible for § 376 treatment.

3. Restructuring implementation costs and restructuring-related costs shall be reviewed for reasonableness. Interested parties may stipulate to the reasonableness of these costs in settlement agreements. Costs incurred for the start-up and development of the ISO, the PX, the CEP, and the EET are found to be reasonable.

4. The revenue cycle services (RCS) implementation costs are not eligible for § 376 treatment to the extent they are incurred after 1998 or are otherwise collected through Commission-authorized fees.

5. Costs eligible for § 376 treatment must be incremental to costs already reflected in base rates. Any avoided costs or any savings associated with net staff reductions, more efficient systems, or discontinued activities that result from restructuring implementation shall be recognized and must offset such costs.

6. All customers benefit from establishing the new market structure, therefore all customers must pay for these costs. Section 376-eligible

costs shall be recovered from all customers, regardless of their procurement choice.

7. All generation-related costs should be recovered through spin-off or divestiture of generation assets or as going forward costs, but shall not be given § 376 treatment.

8. Restructuring-related reasonable program costs should be recoverable from all ratepayers. Edison may also be incurring costs to compete in the new competitive generation marketplace. These costs cannot be recovered through rates, but must be recovered through wholesale or retail markets, as appropriate.

9. PX start-up and development costs are eligible for § 376 treatment, as are the utilities' costs of systems to bid default customer load into the PX. All customers should pay for these costs.

10. No § 376 treatment shall be allowed which imposes costs on retail ratepayers associated with the utilities' wholesale contract responsibilities.

11. No recovery of costs shall be allowed under § 376 if these costs will be recovered through some other mechanism, e.g., FERC-approved rates or directly from customers (for instance, in fees for discretionary services).

12. Restructuring implementation costs shall be recovered through a debit entry to the TRA and shall not be assigned to separate cost categories such as transmission, distribution, etc. This cost recovery approach does not preclude the tracking of particular costs and cost categories for purposes of calculating the PX credit.

Proposed Settlement and Conformance with Adopted Guidelines

In this section, we address the proposed settlement and consider whether the agreement conforms to our Adopted Guidelines. When this proceeding began, the Assigned Commissioner encouraged the parties to attempt to achieve settlement. We find that Edison's proposed settlement is reasonable, in the public interest and consistent with our guidelines. The externally managed costs that are discussed in Edison's settlement allow § 376 treatment and cost recovery for ISO and PX start-up and development costs, CEP costs, and EET costs. We agree that these costs are eligible for § 376 cost recovery, and should be presumed reasonable.

Pursuant to D.97-12-042 and D.98-12-027, we have determined that Edison's share of both the ISO and PX start-up and development costs are eligible for § 376 treatment, whether assessed as a one-time charge or as a volumetric charge. Moreover, funding of these costs has been defined to occur regardless of when the contribution to the development costs is made. We have confirmed that the term "funded" does not imply a specific time when costs are paid for, nor is there a requirement that the financial contribution take place through specific mechanisms. (D.98-12-027, mimeo., at p. 11.)

Costs associated with the PX's start-up and development are assessed through the Initial Charge. The costs associated with the ISO's start-up and development are assessed through the Grid Management Charge. These costs have been incurred by year-end 1998. These costs will be billed over a period extending beyond 1998. We find these charges reasonable and recoverable, including those billed after 1998.

In D.97-03-069, we approved the Consumer Education Program (CEP) to be funded by PG&E, Edison, and SDG&E. The October 30, 1996 Direct Access Working Group (DAWG) Report recommended that utilities be permitted to recover their costs associated with the development and implementation of the CEP. This report stated that such funding was consistent with § 376. We adopted this recommendation and determined that funding requirements for the joint CEP would be allocated among PG&E, Edison, and SDG&E in proportion to each utility's share of actual 1996 sales. We authorized these utilities to establish memorandum accounts under IRMA to track these expenditures. We concluded that the CEP efforts were critical to direct access implementation in order to educate residential and small commercial customers about choices involved in the new market structure and to overcome the mindset of dealing only with the incumbent monopoly utility.

We therefore determined that these costs are recoverable from their customers pursuant to § 376, but left the details of this recovery to other proceedings. A total amount of $23 million was authorized for all three utilities for the joint CEP effort. In D.97-08-064, we authorized a total budget for the joint CEP, Commission outreach activities, and community-based education and outreach activities of $89.3 million (of which $23 million was previously authorized). The utilities' budget for the joint CEP efforts was not to exceed $74.5 million, with Commission and community-based outreach not to exceed $15.8 million. The consumer education program is required by statute (§ 392(b))[7] and we affirm that the costs of the CEP program are eligible for § 376 treatment. Again, PG&E, Edison, and SDG&E are required to fund this program and no other market participant expends costs for this program.

We made similar determinations for the Electric Education Trust (EET) for consumer education activities to take place after the CEP effort concluded. The role of the EET is to promote consumer education in helping customers to understand the changes to the electric industry during the transition period to direct access. We determined that the EET should have a limited lifespan and

[7] Section 392(b) requires that the electric corporations, in conjunction with and subject to the approval of this Commission, implement a consumer education program prior to the implementation of the CTC.

should sunset as of June 30, 1999 unless extended by the Commission or by statute. (D.97-03-069, mimeo., at p. 39.)

After considering various funding options, we determined that public policy would best be served by considering the EET to be part of the implementation costs associated with direct access. We authorized an initial amount of $3 million, to be recoverable from ratepayers pursuant to § 376. In D.98-07-098, we extended the life of the EET to December 31, 2001, pursuant to SB 477 (Stats. 1997, Ch. 275, Section 31). In D.98-12-085, we adopted the recommendation to extend the EET's funding to cover the life of the EET until its scheduled termination date of December 31, 2001. A total of $13.1 million has been allocated for EET funding through 2001, which consists of a $3.1 million education plan and a $10 million community-based organization outreach plan.

These funds were allocated under the same terms and conditions as the original funding and therefore EET costs are eligible for § 376 treatment. This is not inconsistent with our adopted policy, because, similar to funding for the ISO and PX start-up and development, the costs are required by statute and the obligation has been established prior to year-end 1998.

Therefore, we find that it is appropriate to grant cost recovery and § 376 treatment for the EMC costs identified in Edison settlement.

The IMC Costs Recommended for § 376 Treatment in the Proposed Settlement Comports with our Guidelines; the Proposed Cost Recovery of IMCs Also Complies with Those Guidelines

As discussed above, direct access costs are eligible for § 376 treatment only to the extent these costs are required to implement the program through December 31, 1998. The proposed settlement's approach to limiting the IMCs eligible for § 376 treatment is consistent with our guidelines.

In D.97-05-040, we adopted implementation procedures regarding direct access. In this decision, we addressed fundamental procedures and rules to be in place for the provision of direct access. We determined that the availability of direct access mitigated the exercise of market power in the PX and that no technical or operational constraints barred direct access. (D.97-05-040, mimeo., at pp. 15, 18-19.) Therefore, we implemented direct access for all customers as of January 1, 1998, and recognized that the market itself would allow for a gradual development of an interest in customer choice. Of course, as circumstances dictated, the ISO and the PX were not functional until March 31, 1998; therefore, direct access was not initiated until that date.[8] Therefore, all of the elements necessary to allow customer choice were in place as of January 1, 1998, although direct access itself did not begin until March 31, 1998, simultaneously with the implementation of the ISO and the PX.

In D.97-05-040, we observed that PG&E, Edison, and SDG&E had not provided a comprehensive scope of the costs they proposed to include as direct access implementation costs. PG&E and Edison commented that these activities would include, but would not be limited to, consumer education and protection efforts, customer information costs, UDC systems development, implementation, and testing for new capabilities required to interface with the ISO, the PX, and others, installation and reading of real-time pricing meters, UDC billing system modifications required to interface with the ISO, Power Exchange, and others.

We determined that these cost categories were too broad to distinguish which specifically could be attributed to implementation of direct access, but

[8] See D.97-12-031 and Coordinating Commissioner's Ruling in R.94-04-031/I.94-04-032, dated March 30, 1998.

allowed the utilities to track these costs. We directed the utilities to establish memorandum subaccounts to track these costs. We did not guarantee recovery of such costs, but allowed other proceedings to establish procedures to examine whether these tracked costs should be recovered, the reasonableness of these costs, and the recovery of such costs.

In this proceeding, we address and resolve the extent to which restructuring implementation costs incurred by December 31, 1998 can delay recovery of transition costs in accordance with §376. We recognize that certain implementation costs may not be eligible for § 376 treatment but are recoverable costs. Because the settlement agreement limits the amount of IMCs that are eligible for § 376 treatment, this approach is consistent with our guidelines. As discussed, we recognize that we have required the utilities to perform certain programs relating to restructuring that will cause them to incur costs after 1998 in order to carry out our mandates. Consequently Edison's settlement provides for cost recovery for EMCs and IMCs through 2001, and a provision that entitles Edison to seek approval of "Substantial Future Regulatorily Required Restructuring Costs." We approve these provisions. In reviewing the proposed settlement as a whole, we are satisfied that the settlement is in the public interest, reasonable in light of the whole record, and consistent with the law. Section 376 treatment is appropriately limited.

In summary, we adopt the proposed settlement, which provides that internally managed costs are capped and that externally managed costs receive dollar-for-dollar recovery:

(millions of $)

IMC	EMC	Total
$58.6	$151.4	$210[9]
101.4	---	102
$160[10]		$312

Comments on Proposed Decision

The ALJ's revised proposed decision in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. The settling parties timely filed joint comments on August 31, 1999, and Enron filed reply comments on September 7, 1999. After consideration of these comments, the decision has been clarified to better reflect the fact that costs incurred during the rate freeze must be recovered prior to the end of the rate freeze and to indicate that costs and cost categories must be tracked for later inclusion in the PX, RCS, or other credits, if the Commission so authorizes.

---

9 These § 376 costs are capped and may displace transition cost recovery. They are recoverable after March 31, 2002, if the rate freeze does not end by this date. EMCs are estimated and receive dollar-for-dollar recovery.

10 Edison shall not recover any more than this amount of internally managed costs. These costs do not displace transition cost recovery, and Edison is at risk for their recovery.

Findings of Fact

1. Because the costs of establishing the infrastructure underlying the new market structure were not included in rates as of June 10, 1996, the Legislature provided an opportunity for the utilities to be made whole in terms of transition cost recovery.

2. In A.98-05-015, Edison seeks to establish the eligibility of particular cost categories for which § 376 treatment is appropriate and the applicable ratemaking and rate recovery mechanisms.

3. On May 18, 1999, Edison and various parties filed a Motion for Approval of Settlement that would resolve Phase 1 eligibility and Phase 2 reasonableness issues in this proceeding.

4. The proposed settlement would separate costs into externally managed restructuring costs and internally managed restructuring costs.

5. Externally managed restructuring costs consist of FERC-approved ISO and PX start-up and development costs and Commission-approved Consumer Education Program and Electric Education Trust costs.

6. Edison's settlement defines internally managed costs as Direct Access Implementation Costs, PX Load Bidding and Demand Settlement costs, ISO/PX Interface Costs, Hourly Interval Meter Installation and Reading Costs, UDC Billing Systems Modification Costs, and Customer Information Release System Costs.

7. Edison's externally managed costs should be recoverable through the TRA on a dollar-for-dollar basis. The externally managed costs are eligible for § 376 treatment. The internally managed costs will be capped at $160 million, which are recoverable through the TRA. $58.593 million of this amount may receive § 376 recovery.

8. Enron contests Edison's settlement on procedural grounds and because the settlement does not include functionalization of restructuring implementation costs.

9. We find that implementation of programs to accommodate direct access, the ISO, and the PX that are eligible for § 376 treatment are the reasonable and necessary costs incurred for such programs as of December 31, 1998.

10. Allowing § 376 treatment for the costs Edison incurred or were obligated to incur to accommodate implementation of the ISO, PX and direct access as of year-end 1998 allows for necessary post-operation experience and modifications.

11. Costs should be evaluated to determine if they were incurred to (1) establish the new market structure as of December 31, 1998, i.e., accommodate the implementation of the ISO, the PX, and direct access, (2) operate the distribution utility, or (3) comply with other Commission requirements related to restructuring.

12. Reasonable and necessary costs to operate the distribution utility should be recoverable through a separate rate component or the TRA as a separate cost item.

13. The utilities should have an opportunity to recover costs incurred to comply with Commission-mandated direct access programs. Edison may recover restructuring implementation costs and restructuring related costs as set forth in its settlement agreement.

14. Eligible costs that receive § 376 treatment must be incremental to those costs covered in current rates and incremental to those costs that relate to ongoing utility business.

15. It is reasonable to incorporate any avoided costs and associated costs savings into a final determination of costs receiving § 376 treatment.

16. Costs will not be given § 376 treatment if it is determined that these costs will be recovered from customers in another way.

17. Edison's share of both the ISO and PX start-up and development costs are eligible for § 376 treatment.

18. CEP efforts were critical to direct access implementation in order to educate residential and small commercial customers about choices involved in the new market structure and to overcome the mindset of dealing only with the incumbent monopoly utility.

19. The costs of the CEP program are eligible for § 376 treatment.

20. EET costs are eligible for § 376 treatment.

21. In D.97-03-069, we concluded that expenditures incurred by the utilities for purposes of the statewide Consumer Education Program (CEP) should be eligible for § 376 treatment because these costs are necessary to implement direct access.

22. In D.97-08-064, we adopted a final CEP budget of $73.5 million, but linked reasonableness of expenditures to the utilities' success in achieving a goal of 60% awareness of direct access.

23. On September 14, 1998, an Assigned Commissioner's Ruling was issued that determined no further proceedings were necessary, since the CEP achieved the necessary awareness target of 60%.

24. In D.97-03-069, we found that funding the initial level for the Electric Education Trust (EET) by approving § 376 recovery was appropriate.

25. In D.97-08-064, we increased the EET funding level to $13 million.

26. We implemented direct access for all customers without a phase-in because we determined that no technical or operational constraints existed that would require a phase-in.

27. We recognized that the market itself would allow for a gradual development of an interest in customer choice.

28. Because the ISO and the PX were not functional until March 31, 1998, direct access was not initiated until that date.

29. As used in this decision, functionalization can be defined as cost assignment by service or program, which can be distinguished from cost allocation, which assigns cost responsibility by customer group.

30. We will not further functionalize restructuring implementation costs at this time, but do not preclude the possibility of particular costs being included in the PX credit or other credits.

31. Recovery of restructuring-related costs through the TRA will not preclude the subsequent inclusion of certain of these costs in the PX credit or other credits such as RCS credits if the Commission so determine. The utilities must track with specificity all costs and cost categories collected pursuant to this settlement which may be included in such credits.

32. We have adopted stringent criteria for allowing § 376 treatment of restructuring implementation costs, which have been incurred to create the new market structure.

33. All customers, whether bundled or direct access, benefit from the creation of the new competitive regime. Consistent with cost causation principles, all customers must bear the burden of these costs.

34. Costs found reasonable and related to restructuring activities that are not eligible for § 376 treatment are recoverable from customers.

35. We will develop a methodology to compare these costs and the necessity for extending CTC in A.99-01-016 et al., the proceedings we have established to review post rate freeze ratemaking methodology.

Conclusions of Law

1. The settlement before us is reasonable in light of the whole record, consistent with the law and in the public interest, and should be approved.

2. Section 376 does not directly authorize recovery of PX and ISO implementation costs, but extends the period for recovery of generation-related plant and regulatory assets to the extent that the opportunity to recover these assets has been reduced by the collection of specified implementation costs.

3. If Edison fully recovers its generation-related transition costs before December 31, 2001, § 376 will not be triggered.

4. Section 376 does not define implementation and we cannot find that implementation necessarily lasts until December 31, 2001.

5. Since the Legislature determined the length of the transition period and was aware of the residual nature of CTC recovery, the Legislature could easily have prescribed that the implementation period was the same as the transition period, but did not do so.

6. Limiting § 376 treatment to the reasonable costs of implementation of the PX, the ISO, and direct access in 1997 and 1998 ensures that we are properly considering the intent of § 376.

7. The Legislature determined that there were certain costs to be expended on new programs to implement the Power Exchange, the Independent System Operator, and direct access.

8. In §§ 367 and 368, the Legislature afforded the utilities the opportunity to recover assets that might become uneconomic in the new competitive generation market by providing for a rate freeze and subsequent recovery of such transition costs during the transition period.

9. It would be inequitable to require that these new programs be established and provide the opportunity for full transition cost recovery, without providing

for some mechanism to ensure that the costs of implementing the new programs do not interfere with transition cost recovery.

10. Pursuant to D.97-12-042 and D.98-12-027, we have determined that these costs are eligible for § 376 treatment, whether assessed as a one-time charge or as a volumetric charge.

11. Funding of ISO and PX start-up and development costs has been defined to occur regardless of when the contribution to the development costs is made.

12. In D.98-07-098, we extended the life of the EET to December 31, 2001, pursuant to SB 477 (Stats. 1997, Ch. 275, Section 31). In D.98-12-085, we adopted the recommendation to extend the EET's funding to cover the life of the EET until its scheduled termination date of December 31, 2001.

13. Similar to funding for the ISO and PX start-up and development, the costs of certain consumer education programs are required by statute and the obligation has been established prior to year-end 1998.

14. The proposed settlement's treatment of externally managed costs is consistent with our guidelines.

15. The proposed settlement's recommendation to recover externally managed costs through the TRA is reasonable and conforms to the guidelines adopted for cost recovery.

16. In D.97-05-040, we adopted implementation procedures regarding direct access, addressed fundamental procedures and rules to be in place for the provision of direct access, and determined that the availability of direct access mitigated the exercise of market power in the PX.

17. All of the elements necessary to allow customer choice were in place as of January 1, 1998, although direct access itself did not begin until March 31, 1998, simultaneously with the implementation of the ISO and the PX.

18. We established memorandum subaccounts in D.97-05-040 to track costs attributed to implementation of direct access.

19. The Legislature did not provide for costs incurred by ESPs to be recovered from the general body of incumbent utility ratepayers. Such costs are simply a cost of doing business by the ESP.

20. Identification and recovery of restructuring implementation costs should be addressed in this proceeding. Restructuring- related costs other than implementation costs should be recoverable, as set forth in Edison's settlement.

21. Only those costs incurred to accommodate implementation of the ISO, PX, and direct access through December 31, 1998 shall receive § 376 treatment. Therefore, costs incurred after 1998 are not eligible for § 376 treatment and the costs of operating these programs on an ongoing basis are not eligible for § 376 treatment.

22. Costs incurred for the start-up and development of the ISO, the PX, the CEP, and the EET are reasonable.

23. Edison's proposed treatment of internally managed costs is consistent with our guidelines, and therefore, its settlement should be approved.

24. Prior to the end of the rate freeze it is reasonable that Edison recover restructuring implementation costs deemed eligible for § 376 treatment through debits to the TRA as set forth in the settlement agreement.

25. In general, restructuring implementation costs benefit all customers and must be paid for by all customers.

26. We have long held to the standard that the purchaser or user of a service should bear responsibility for those costs. In general, all customers must pay for costs that benefit all customers. It is reasonable to adopt these principles for costs receiving § 376 treatment; however, this does not preclude tracking of

implementation and other restructuring costs for inclusion in the PX, RCS, or other credits.

27. Enron's functionalization proposal is rejected in this proceeding, but this does not preclude tracking with specificity all costs to be reflected in the PX, RCS, or other credits.

28. Consistent with Rule 51.7, this decision proposes a modification to the settlement that clarifies that all restructuring-related costs not given § 376 treatment must be recovered prior to the end of the rate freeze. Edison and the settling parties should file joint comments within 15 days of the effective date of this decision to indicate that this modification is acceptable.

29. This order should be effective today, so that the settlement may be implemented expeditiously.

FINAL ORDER

IT IS ORDERED that:

1. The motion of Southern California Edison Company (Edison), California Farm Bureau Federation, California Large Energy Consumers Association, California Manufacturers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition, the Office of Ratepayer Advocates, the Utility Reform Network, the University of California, the State University of California, and California Industrial Users for Approval of Settlement Agreement, filed on May 18, 1999, and set forth in Attachment 1, is granted, provided Edison and the settling parties accept the modification addressed herein.

2. Edison and the settling parties shall file joint comments within 15 days of the effective date of this decision to indicate their acceptance of the clarified approach to recovery of restructuring-related costs.

This order is effective today.

Dated September 16, 1999, at San Francisco, California.

RICHARD A. BILAS
President
HENRY M. DUQUE
JOSIAH L. NEEPER
JOEL Z. HYATT
CARL W. WOOD
Commissioners

I will file a concurrence.

/s/ JOSIAH L. NEEPER
Commissioner

ATTACHMENT 1

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Pacific Gas and Electric Company, to establish the eligibility and seek recovery of certain electric industry restructuring implementation costs as provided for in Public Utilities Code Section 376.	Application 98-05-004
San Diego Gas & Electric Company, for (1) a determination of eligibility for recovery under Public Utilities Code Section 376 of certain cost categories and activities, (2) a finding of reasonableness of the costs incurred through 12/31/97, (3) approval of an audit methodology for verifying the eligibility of Section 376 costs for recovery from 1998 through 2001, and (4) approval of a Section 376 balancing account mechanism to recover eligible costs.	Application 98-05-006
Southern California Edison Company, to address restructuring implementation costs pursuant to Public Utilities Code § 376, in compliance with Ordering Paragraph 18 of D.97-11-074.	Application 98-05-015

SETTLEMENT AGREEMENT OF

CALIFORNIA ASSOCIATION OF COGENERATORS,

CALIFORNIA FARM BUREAU FEDERATION

CALIFORNIA INDUSTRIAL USERS

CALIFORNIA MANUFACTURERS ASSOCIATION,

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION,

ENERGY PRODUCERS AND USERS COALITION,

OFFICE OF RATEPAYER ADVOCATES,

THE UTILITY REFORM NETWORK,

UNIVERSITY OF CALIFORNIA,

CALIFORNIA STATE UNIVERSITY, AND

SOUTHERN CALIFORNIA EDISON COMPANY

ATTACHMENT 1

TABLE OF CONTENTS

Page

I. PARTIES 2

II. RECITALS 2

A. Scope Of The Agreement 2

B. Settlement Process 3

C. SCE's Position 6

D. ORA's Position 6

E. The California Manufacturers Association's And The California Large Energy Consumers Association's Position 8

F. The California Industrial Users Position 9

G. The Energy Producers And Users Coalition's And California Association Of Cogenerators' Position 9

H. The California Farm Bureau's Position 9

I. The Utility Reform Network's Position 10

J. The University of California's And California State University's Position 10

III. DEFINITIONS 11

A. Externally Managed Costs (EMCs) 11

B. Internally Managed Costs (IMCs) 11

C. Other Industry Restructuring Costs (OIRC) 11

D. Section 376 Internally Managed Costs (§ 376 IMCs) 12

E. Substantial Future Regulatorily Required Restructuring Costs 12

F. Transition Period 12

G. CTC Displacement Amount 13

IV. AGREEMENT 13

A. Authorized Cost Recovery Amount 13

B. Cost Recovery Mechanism 14

C. Derivation Of CTC Displacement Amount 15

D. CTC Displacement Tracking Account Mechanism 15

E. Capitalizing Versus Expensing 16

F. "Going Forward Cost" Recovery 17

G. No Section 375 recovery 17

H. Substantial Future Regulatorily Required Restructuring Costs 18

I. Further Reviews And Adjustments 19

V. ADDITIONAL TERMS AND CONDITIONS 20

A. Term Of Settlement Agreement 20

B. Obligation To Promote Approval 20

C. Public Interest 21

D. Non-Precedential Effect 21

E. Indivisibility 21

F. Liability 22

G. Governing Law 22

H. Interpretation 22

I. No Waiver 22

J. Amendment/Severability 23

K. Counterparts 23

ATTACHMENT 1

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Pacific Gas and Electric Company, to establish the eligibility and seek recovery of certain electric industry restructuring implementation costs as provided for in Public Utilities Code Section 376.	Application 98-05-004
San Diego Gas & Electric Company, for (1) a determination of eligibility for recovery under Public Utilities Code Section 376 of certain cost categories and activities, (2) a finding of reasonableness of the costs incurred through 12/31/97, (3) approval of an audit methodology for verifying the eligibility of Section 376 costs for recovery from 1998 through 2001, and (4) approval of a Section 376 balancing account mechanism to recover eligible costs.	Application 98-05-006
Southern California Edison Company, to address restructuring implementation costs pursuant to Public Utilities Code § 376, in compliance with Ordering Paragraph 18 of D.97-11-074.	Application 98-05-015

SETTLEMENT AGREEMENT OF

CALIFORNIA ASSOCIATION OF COGENERATORS,

CALIFORNIA FARM BUREAU FEDERATION

CALIFORNIA INDUSTRIAL USERS

CALIFORNIA MANUFACTURERS ASSOCIATION,

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION,

ENERGY PRODUCERS AND USERS COALITION,

OFFICE OF RATEPAYER ADVOCATES,

THE UTILITY REFORM NETWORK,

UNIVERSITY OF CALIFORNIA,

CALIFORNIA STATE UNIVERSITY, AND

SOUTHERN CALIFORNIA EDISON COMPANY

I.
PARTIES

The parties to this Settlement Agreement are the California Association of Cogenerators (CAC), California Farm Bureau Federation (CFBF), California Industrial Users (CIU), California Large Energy Consumers Association (CLECA), California Manufacturers Association (CMA), Energy Producers and Users Coalition (EPUC), Office of Ratepayer Advocates of the California Public Utilities Commission (ORA), The Utility Reform Network (TURN), University of California (UC), California State University (CSU), and Southern California Edison Company (SCE), (collectively, Parties).

II.
RECITALS

A. Scope Of The Agreement

Public Utilities Code § 376 (§ 376) provides that to the extent electric utilities' opportunity to recover their competition transition charges (CTCs) is reduced by the cost of programs to accommodate implementation of direct access, the Independent System Operator (ISO), and Power Exchange (PX), utilities are authorized recovery of their unrecovered CTCs, if any, in rates after December 31, 2001. Pursuant to Ordering Paragraph 18 of Decision 97-11-074, on May 1, 1998, SCE filed Application 98-05-015.[1/] That application was consolidated with the parallel applications of Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E). Each of the applicant utilities sought recovery of costs incurred during 1997 as described in their respective applications. In addition, each of the utilities sought Commission findings approving the categories of costs described in their respective applications as eligible for the transition cost carryover effect of Public Utilities Code § 376.

1/ D.97-11-074 ordered the utilities to file applications by March 31, 1998. This date was extended to May 1, 1998 in a March 25, 1998, letter from the Commission's Executive Director.

Genuine disputes have existed among the Parties concerning: (1) SCE's level of generation-related CTCs which will be displaced during the transition period by the cost of programs to accommodate implementation of direct access, the ISO and PX, pursuant to Public Utilities Code § 376 and the interpretation thereof, (2) the mechanism for tracking displaced CTCs, (3) the level of cost recovery of SCE's direct access, ISO and PX costs which shall be recovered in rates, and (4) the cost recovery mechanism. This Settlement Agreement resolves these issues. This Settlement Agreement also resolves, without further investigation, review (including reasonableness reviews), adjustments, or litigation, all issues identified as Phase 1 and Phase 2 issues in the Assigned Commissioner's Ruling dated July 10, 1998. The Parties agree that this Settlement Agreement sets forth the methodology for determining the amount of displaced CTCs to be recovered, if any, after December 31, 2001. This Settlement Agreement does not resolve how any post-2001 CTC Displacement Amounts will be recovered in rates.

B. Settlement Process

Pursuant to Ordering Paragraph 18 of Decision 97-11-074, on May 1, 1998, SCE filed Application 98-05-015.[2] That application was consolidated with the parallel applications of Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E).

A prehearing conference was held on June 25, 1998, during which Commissioner Bilas strongly encouraged the parties to explore settlements. Shortly after that prehearing conference, SCE entered into discussions with several of the parties to this proceeding aimed at narrowing the differences in their respective positions. These discussions were continued during and subsequent to a meet and confer session on August 11, 1998, which was reported to the Commission in a Case

2/ D.97-11-074 ordered the utilities to file applications by March 31, 1998. This date was extended to May 1, 1998 in a March 25, 1998, letter from the Commission's Executive Director. D.97-11-074, [*mimeo*], p. 210.

Management Statement filed jointly on August 24, 1998 by many active parties to this docket.

Despite these efforts at achieving consensus as to a reasonable outcome of this proceeding, they were unable to do so prior to the scheduled date for the commencement of evidentiary hearings. Accordingly, SCE's case-in-chief proceeded to seven days of evidentiary hearings between October 21, and November 3, 1999. Opening and reply briefs were then filed regarding SCE's application on November 24, and December 15, 1999, respectively.

Meanwhile, following duly noticed settlement conferences, PG&E and SDG&E each reached settlements with several of the parties to this proceeding. Motions seeking approval of those settlements were filed with the Commission on November 12 (SDG&E), and November 13, 1999 (PG&E).

On March 11, 1999, ALJ Minkin issued separate proposed decisions, one addressing SCE's application and one addressing the PG&E and SDG&E settlements. Commissioner Bilas concurrently issued an Alternate Decision corresponding to each of ALJ Minkin's proposed decisions. Parties filed comments on these proposed and alternate decisions on March 31, 1999, followed by replies on April 5, 1999. Both ALJ Minkin's Proposed Decision and Commissioner Bilas' Alternate Decision would have rejected the settlements.

On April 8, 1999, Commissioner Neeper issued an Alternate Decision, which would have approved the settlements. Several of the Parties filed comments on Commissioner Neeper's Alternate on April 15, 1999.

On April 19, 1999, oral argument was held before the full Commission on both SCE's application and the proposed settlements.

On April 23, 1999, ALJ Minkin issued a revised proposed decision on both SCE's application and the proposed settlements. Unlike the earlier version, the revised proposed decision would approve the PG&E settlement *in toto,* and the SDG&E settlement with some proposed modifications.

Meanwhile, during the two weeks preceding the oral argument, there were several all-party meetings with the Commissioners. Although prior to evidentiary hearings the parties had been unable to resolve their differences, after fully litigating their respective positions, after presenting those positions in all-party meetings, and, most importantly, with the added perspective of two versions of ALJ Minkin's proposed decision and alternate decisions from two Commissioners, ORA and SCE, plus several other parties, decided to resume discussions aimed at achieving a settlement agreement. This time those discussions proved successful. On April 27, 1999, ORA and SCE reached an understanding as to principles on which they would agree to settle the Phase 1 and Phase 2 issues in this proceeding. A copy of those principles was then provided to the CAC, CFBF, CIU, CLECA, CMA, EPUC, and TURN. On May 4, 1999, representatives of several of these parties met to discuss the settlement principles on which ORA and SCE had agreed. On May 5, 1999, ORA and SCE jointly noticed a Settlement Conference for May 12, 1999. A draft of the Settlement Agreement was appended to that notice.

Concurrent with the notice of settlement conference, ORA and SCE also filed a petition pursuant to Rule 84 to set aside submission of A.98-05-015, in order to give the Commission an opportunity to consider the anticipated settlement. On May 10, 1999, ALJ Minkin issued a ruling in response to that joint petition, directing parties to file responses no later than May 12, 1999, and also noting: "Although this response time is quite short, parties have been aware of the possibility of settlement discussions since the oral argument on April 19.[3/] Enron Corp was the only party to file a response to the petition.

During the interim period between noticing the Settlement Conference and the date of that conference, several parties contacted ORA and SCE with specific questions or concerns about the text of the draft Settlement Agreement. Those

---

3/ ADMINISTRATIVE LAW JUDGE'S RULING REGARDING RESPONSES TO MOTION TO SET ASIDE SUBMISSION, dated May 10, 1999, p. 2.

questions and concerns were discussed as they arose individually with the parties that raised them.

The Settlement Conference was held as scheduled on May 12, 1999. During that Settlement Conference, parties in attendance[4] were provided a new draft agreement, which incorporated various comments parties had made regarding the draft circulated on May 5, 1999. After the Settlement Conference, the Settling Parties signed the attached Settlement Agreement.

On May 13, 1999, the Commission voted to adopt Commissioner Neeper's Alternate Decision (D.99-05-031), which approved the PG&E and SDG&E settlements. Finally, on May 18, 1999, this motion was filed with the Commission.

C. SCE's Position

SCE's proposal for identifying and recovering costs subject to § 376 is contained in its prepared direct and rebuttal testimony and accompanying workpapers filed as SCE's Application in the instant proceeding. In addition, SCE has responded to a large number of data requests.

SCE has maintained throughout this proceeding that all the 1997 recorded costs described in its application should be approved for recovery from ratepayers. Subsequent applications would address the reasonableness of costs recorded subsequent to 1997. In addition, SCE's position has been that all the programs described in its application should be approved for § 376 treatment, subject to a self-imposed cap of $275 million. Nonetheless, SCE believes that the accompanying settlement presents a fair resolution of the issues.

D. ORA's Position

The Office of Ratepayer Advocates ("ORA") actively participated in this proceeding, including reviewing SCE's filing in detail, engaging in extensive discovery with regard to Phase 1 issues (from which ORA adduced information regarding Phase 2), presenting the testimony of several witnesses addressing issues raised by SCE's application (Exhibits 9, 34), filing post-hearing briefs, commenting on the proposed and alternate decisions, and participating in the oral argument before the Commission. While ORA was concerned with several issues raised by SCE's application, its primary concern was with two issues. First, ORA was concerned that SCE used an overly broad definition of "implementation." Second, ORA was concerned that the need for ongoing reasonableness review and the failure to examine costs before the fact could lead to insufficient utility effort to control such costs and would use disproportionate amounts of regulatory resources to review those costs.

ORA is satisfied that the limit on § 376 eligibility embodied in this Settlement Agreement adequately addresses its concerns with the broadness of SCE's request. The Settlement agreement limits § 376 eligibility to SCE's actual externally managed costs (eligible categories are forecast to be $151.407 million) plus $58.593 million of internally managed costs, for an estimated total of $210 million in § 376 eligible costs. In ORA's view, this compares favorably to SCE's request that the Commission approve its estimated expenditures of approximately $430 million as eligible for § 376 treatment (subject to SCE's self-imposed cap of $275 million).

ORA is further satisfied that an authorization for SCE to recover no more than $160 million of transition period internally managed costs, as reflected in the Settlement Agreement, responds to ORA's concerns about regulatory process and utility management control over cost incurrence. The $160 million cap on SCE's internally managed costs represents a $110 million reduction from SCE's August 20, 1998 forecast of such costs.[5/] Furthermore, the Settlement Agreement avoids the need for reasonableness review of both costs which have been and will be

---

4 Attending the settlement conference were representatives of CLECA, Enron, ORA, PG&E, SCE, TURN, and SDG&E.

incurred. Based on ORA's review of internally managed costs, the $160 million recovery authorization provides the appropriate means and responsibility to SCE to manage a reasonable level of costs. Ratepayers have a high level of certainty of cost exposure for the totality of restructuring transition costs, although this certainty is not absolute. ORA is satisfied that provisions of the Settlement Agreement dealing with substantial future regulatorily required restructuring costs provide a limit on SCE's ability to seek any further costs, while providing SCE a fair opportunity to deal with future regulatory mandates which impose substantial costs for new programs upon SCE.

E. The California Manufacturers Association's And The California Large Energy Consumers Association's Position

CMA and CLECA sponsored the testimony of Dr. Barkovich in this proceeding (Exhibit 19). Dr. Barkovich's testimony set forth several principles which she recommended the Commission utilize in evaluating the eligibility of various costs for § 376 treatment. Overall, Dr. Barkovich recommended that the Commission maintain the balance between utility and ratepayer interests contemplated in AB 1890. In addition, CMA and CLECA filed post-hearing briefs and comments on the proposed and alternate decisions, and participated in the oral argument before the Commission.

CMA and CLECA believe that the Settlement Agreement is consistent with the principles set forth in Dr. Barkovich's testimony and believe the cap on § 376 costs contained in the Settlement is a reasonable resolution of these issues. CMA and CLECA support the Settlement and believe that its treatment of restructuring costs is consistent with prior Commission decisions and AB 1890.

5/ SCE's forecast of total restructuring costs was $430 million, comprised of $151.407 million of EMCs and $278.593 million of IMCs.

F. The California Industrial Users Position

CIU participated in this proceeding through the cross-examination of witnesses, post-hearing briefs, comments on the proposed and alternate decisions, and participation in oral argument before the Commission. The issues of primary interest to CIU throughout the proceeding have been application of the principle of competitive neutrality and the proper scope of the interpretation of § 376, which CIU believed SCE had interpreted too expansively. With regard to the latter issue, CIU's position has been that the ISO, PX, and direct access were all implemented by March 31, 1998. Therefore, CIU's position has been that eligibility for costs to receive the transition cost carryover effects of § 376 should end no later than December 31, 1998. CIU believes the Settlement Agreement represents a fair resolution of the issues in this proceeding.

G. The Energy Producers And Users Coalition's And California Association Of Cogenerators' Position

EPUC and CAC sponsored the testimony of James A. Ross (Exhibit 45). Mr. Ross testified that § 376 eligible costs should be limited to only those costs that are necessary to implement direct access, the PX or the ISO, and which are not recovered from other sources. In addition, EPUC and CAC filed post-hearing briefs and participated in the oral argument before the Commission. EPUC and C.A.C. are satisfied that the Settlement Agreement furthers the goal of limiting charges to customers, as contemplated by Mr. Ross, and is a reasonable resolution of disputed issues.

H. The California Farm Bureau's Position

CFBF participated in this proceeding through cross-examination of witnesses and the filing of comments on the proposed and alternate decisions. CFBF also participated in oral argument before the full Commission on these issues. CFBF's principal concern in this proceeding has been that the utilities' distribution rates not be used as the vehicle for recovery of restructuring-related costs. CFBF believes the Settlement Agreement represents a fair resolution of the issues in this proceeding.

I. The Utility Reform Network's Position

TURN participated in this proceeding through the testimony of its witness, Michel Florio (Exhibits 42 and 43), and through the filing of post-hearing briefs and comments on the proposed and alternate positions. TURN also participated in oral argument before the full Commission in this proceeding. TURN recommended a number of principles that should govern the Commission's decision-making in this proceeding. TURN's principal concern has been that the utilities' distribution rates not be used as the vehicle for recovery of restructuring-related costs. TURN believes this Settlement Agreement represents a fair resolution of the issues in this proceeding.

J. The University of California's And California State University's Position

The UC and CSU participated in this proceeding as signatories to the settlements of PG&E's and SDG&E's applications and through filing comments on ALJ Minkin's Proposed Decision and Commissioner Bilas' Alternate. UC and CSU believe the Settlement Agreement, with the caps on § 376 eligibility and recovery of IMCs, is consistent with the balance of utility customer and shareholder interests reflected in AB 1890. UC and CSU therefore support the Settlement Agreement as a reasonable resolution of how restructuring implementation costs should be treated.

III.
DEFINITIONS

A. Externally Managed Costs (EMCs)

EMCs are defined as the actual amounts for the PX Initial Charge, the start-up and development portion of the ISO grid management charge, and Consumer Education Program, Electric Education Trust Costs, and related Commission approved customer educational costs. Upon Commission approval of this Settlement Agreement, EMCs for the enumerated programs will be determined to "have been funded by SCE and have been found by the Commission or the Federal Energy Regulatory Commission to be recoverable from the utility's customers" pursuant to § 376.

B. Internally Managed Costs (IMCs)

IMCs are defined as the following costs described in SCE's testimony in this proceeding and the schedules prepared at the request of the Assigned Administrative Law Judge and appended to SCE's June 10, 1998 prehearing conference statement (incorporated herein by reference): Direct Access Implementation Costs; Hourly Interval Meter Installation and Reading Costs; UDC Billing Systems Modification Costs; Customer Information Release Systems Costs; and Utility Energy Supply Forecast. In addition, costs associated with the Universal Node Identifier System (UNIS), (see D.98-11-044) are also to be considered IMCs.

Upon adoption of this Settlement Agreement, IMCs for the enumerated programs will be determined to "have been funded by SCE and have been found by the Commission or the FERC to be recoverable from the utility's customers" pursuant to § 376. Recovery of IMCs shall be capped at $160 million.

C. Other Industry Restructuring Costs (OIRC)

Other Industry Restructuring Costs (OIRCs) are defined herein as the following costs described in SCE's testimony in this proceeding (incorporated herein by reference) and included in the schedules appended to SCE's June 18, 1998 prehearing conference statement in this proceeding:[6] Power System Control Modifications; Meter Certification; Electric Supply Settlement System; Generation ISO/PX Settlement, Billing, and Bidding Systems; and, Western Power Exchange Project.

D. Section 376 Internally Managed Costs (§ 376 IMCs)

Section 376 IMCs are the portion of IMCs which is eligible to displace CTCs during the transition period, pursuant to Section IV.D. As discussed herein, the level of § 376 IMCs is fixed at $58.593 million.

E. Substantial Future Regulatorily Required Restructuring Costs

Substantial future regulatorily-required restructuring costs are defined as costs for a new restructuring-related program which represents a substantial departure from the current restructuring-related programs. Such costs are those which SCE will be required to incur due to a regulatory decision of the Federal Energy Regulatory Commission (FERC) or the Commission and which are imposed after the submission of this Settlement Agreement. The Parties define a "substantial" event as a FERC or Commission decision which imposes costs of $ 2.0 million or greater in revenue requirement prior to January 1, 2002, for a single restructuring-related, direct access, ISO, or PX program.

F. Transition Period

For purposes of this Settlement Agreement, the term "transition period" refers to the period 1997-2001.

6/ Each of the applicant utilities in this proceeding was directed to present their respective cost estimates using a format prescribed in a June 3, 1998 ALJ Ruling.

G. CTC Displacement Amount

"CTC Displacement Amount" is the level of generation-related CTCs which are unrecovered at the end of the transition period due to the recovery of 376 IMCs and EMCs during the transition period.

IV.
AGREEMENT

The Parties to this Settlement Agreement recognize that SCE's Application and the Parties' analysis of that Application consist in significant part of forecasts (sometimes referred to as "estimates"). The level of costs recommended by the Parties is based upon the Parties' individual judgments regarding the strengths and weaknesses of competing forecasting methodologies, and the resulting compromises each Party believes are reasonable.

The Parties regard this Settlement Agreement as a package which reflects substantial compromise among the Parties. The resolved issues are interrelated and no issue or term of the Settlement Agreement should be evaluated in isolation from the remainder of the package. (See Section V.E, "Indivisibility," below).

All dollar amounts expressed in this Settlement Agreement are in nominal dollars unless otherwise noted.

In addition, the Parties agree to the provisions set forth below.

A. Authorized Cost Recovery Amount

The Parties agree that the level of cost recovery for direct access, the ISO and PX expenditures during the transition period shall consist of the sum of (1) EMCs and (2) IMCs.

The Parties agree that SCE shall be authorized to recover the full amount of EMCs on a dollar-for-dollar basis.[7/] To this end, the Parties agree that SCE's level

7/ In its application for recovery of section 376 costs (Application 98-05-015, Exhibit SCE-2, Page 2), SCE indicated that the current deductibility of the PX start-up and development costs for income tax purposes was unclear. As a result, SCE proposed to seek a private letter ruling from the Internal Revenue Service (IRS) as to the proper tax treatment. That request was made on March 12, 1999. As yet, however, the of recoverable EMCs shall be the actual amounts, including payments or credits, or other amounts billed or assigned to SCE, whether these actual amounts exceed or are less than the estimated amounts for EMCs. The Parties agree that SCE shall continue to track its EMCs through the earlier of the date SCE is determined to have recovered its CTCs or December 31, 2001. In the event that tracking continues through December 31, 2001, SCE shall determine its total EMCs as of December 31, 2001.

The Parties agree that SCE shall recover the revenue requirements associated with actual expenditures on IMCs, capped at $160 million. In the event SCE expends less than $160 million on IMCs, ratepayers would be responsible for the actual amounts incurred.

B. Cost Recovery Mechanism

The Parties agree that the levels of SCE's direct access, ISO and PX expenditures, as specified in Section IV.A above, are recoverable in accordance with the cost recovery mechanism set forth in this section.

During the rate freeze period, the authorized restructuring implementation costs, other than the "going forward costs" discussed in Section IV.F of this Settlement Agreement, will be recovered through a monthly debit entry to the Transition Revenue Account (TRA). Once the rate freeze ends and the TRA is eliminated, the revenue requirement associated with these costs will be recovered through such rate component which may be adopted by the Commission in SCE's Post-Transition Ratemaking proceeding for the recovery of such costs.

The Parties agree that after the Commission adopts the methodology for design of such a rate component after the transition period, SCE shall file an annual Advice Letter to establish the rate to recover the IMC and EMC revenue

IRS has not ruled on that request. Should the IRS rule that these costs are not currently deductible, the parties agree that the level of EMCs agreed upon in this Settlement Agreement would be increased to include the net present value of any applicable taxes due, net of allowed amortization or depreciation, using the TCBA rate of return as the discount factor and that SCE would be allowed to recover such costs.

requirements. Except for this advice letter filing, the Parties agree that neither the level of IMCs, § 376 IMCs or EMCs to be recovered in rates nor the cost recovery mechanism requires any further filing or request by SCE or any approval of the Commission or any Party other than the Commission's approval of this Settlement Agreement.

On a monthly basis, after the end of the rate freeze, or as soon as authorized by the Commission, SCE will compare billed revenues from the rate component described above to actual total EMCs and IMCs. Any overcollections or undercollections resulting from this comparison will be reflected in the subsequent year's rate component. Any overcollections or undercollections resulting from this comparison will receive the three-month commercial rate of interest.

C. Derivation Of CTC Displacement Amount

The Parties agree that SCE's CTC Displacement Amount shall consist of the sum of (1) EMCs and (2) § 376 IMCs.

The Parties agree that SCE shall be authorized to recognize EMCs on a dollar-for-dollar basis for purposes of determining the level of EMCs, and to track EMCs as discussed above in Section IV.A.

The Parties agree that SCE shall be authorized to recognize $58.593 million in § 376 IMCs for the purpose of determining the CTC Displacement Amount at the conclusion of the transition period. The § 376 IMC amount is fixed, not subject to adjustment.

D. CTC Displacement Tracking Account Mechanism

SCE agrees to enter each month the total amount of EMCs and § 376 IMCs in a new "CTC Displacement Tracking Account." SCE agrees to compare the total amount entered in the "CTC Displacement Tracking Account" to SCE's Transition Cost Balancing Account ("TCBA") balance to evaluate SCE's reduced opportunity to recover its CTCs during the transition period. If, at the end of the transition period, the TCBA reflects an undercollection of CTCs which is less than or equal to the amount recorded in the CTC Displacement Tracking Account, then SCE shall be entitled to recover the TCBA Undercollection after the transition period. If, at the end of the transition period, the TCBA reflects an undercollection of CTCs greater than the amounts recorded in the CTC Displacement Tracking Account, then SCE shall recover the amount in the CTC Displacement Tracking Account.

E. Capitalizing Versus Expensing

The ALJ's proposed decision recommended that SCE expense all costs incurred for both book and tax purposes. However, it is ORA's and SCE's position that the Internal Revenue Code mandates the required tax treatment of computer software as well as the tax treatment of other capital assets that are subject to the Accelerated Cost Recovery System (ACRS) and/or Modified Accelerated Cost Recovery System (MACRS) depreciation. SCE and ORA agree that internally developed software can be expensed for tax purposes. ORA and SCE agree to expense this software in computing regulatory tax expense.

SCE has identified $10 million of other assets as of December 31, 1998 that must be capitalized for tax purposes, regardless of ratemaking treatment. The Parties agree that these costs will be expensed in computing regulatory book expense; these costs will be capitalized and depreciated in computing regulatory tax expense following the Internal Revenue Code; and in accordance with Internal Revenue Code § 168, deferred taxes will be computed on all book-tax differences caused by this disparate treatment. Those deferred taxes will earn a return at the CTC rate of return and will be included in the Transition Revenue Account (TRA). Further, any additional expenditures or costs incurred after December 31, 1998, that are treated as expenses in computing regulatory book expense, but that must be capitalized and depreciated or amortized pursuant to the Internal Revenue Code, will be afforded the same treatment.

F. "Going Forward Cost" Recovery

In A.98-05-015, SCE also identified certain costs related to the following: Generation Settlement, Billing, and Bidding Systems; Power System Control Modifications; Meter Certification; Electric Supply Settlement System; and, Western Power Exchange Project (described in Section III.C as "Other Industry Restructuring Costs"). Rather than treat these costs as restructuring-implementation costs, the Parties agree that SCE will instead treat them as generation "going forward costs." Specifically, these costs will be allocated to generation plants based on plant output during the first quarter of 1999. If a plant is "market valued," the costs allocated to that plant will be reallocated to the remaining plants of that fuel type (*i.e.*, Hydro, Nuclear, or Coal). Costs recorded prior to Commission approval of this agreement will be recovered as a generation "going forward cost" in 1999. Costs incurred after Commission approval of this agreement will be recovered as generation "going forward costs" in the year which they are incurred. Costs allocated to Hydro and Nuclear plants will be recorded as revenue reductions and costs allocated to Coal will be recorded as an expense for ratemaking purposes. Costs allocated to Nuclear plants will be recorded in the Current Costs Subaccount (for SONGS and Palo Verde respectively) of the Transition Cost Balancing Account. Those allocated costs will be a reduction to recorded revenue in the respective subaccounts. Costs allocated to Hydro will be recorded in the Hydro Generation Memorandum Account as a reduction to recorded revenue. The costs allocated to Coal will be debited to the Power Exchange Revenue Memorandum Account as a "going forward cost" under category "k" of SCE's Preliminary Statement for the Power Exchange Revenue Memorandum Account, entitled "Other Costs the Commission May Authorize."

G. No Section 375 recovery

SCE agrees not to seek Public Utilities Code § 375 recovery of any employee related transition costs for any new or existing employee performing activities described in A.98-05-015. This agreement does not affect SCE's existing request for recovery of specified employee-related transition costs in the Annual Transition Cost Proceeding, A.98-09-008.

H. Substantial Future Regulatorily Required Restructuring Costs

The Parties understand that the past, present and future programs covered by this Settlement Agreement are subject to significant revision and modification. In light of the possibility that FERC or Commission decisions finalized after the date of submission of this Settlement Agreement to the Commission relating to restructuring, the ISO or PX may substantially affect SCE's ability to recover restructuring costs, the Parties hereby provide for a limited exception for such major events. Therefore, the Parties agree that SCE shall have the opportunity to seek recovery of substantial future regulatorily required restructuring costs as specified below.

If SCE determines a substantial event has occurred, or if the FERC or the Commission is considering issues which could lead to a substantial event, SCE agrees to promptly meet and confer with the other signatory Parties. The Parties shall discuss issues raised by the event SCE determines is substantial and shall make good faith efforts to resolve such issues. If all Parties agree, SCE may seek recovery of the cost associated with the new regulation by application or advice letter. However, the Parties need not agree on the identification or resolution of any issues. Parties may take such positions as they see fit with respect to Commission or FERC consideration of the substantial event. SCE's filing to the Commission shall cite ordering paragraphs of the FERC or Commission decision which supports SCE's claim that there is a new restructuring-related program (one not in existence as of the date of submission of this Settlement Agreement to the Commission) which represents a substantial departure from current restructuring-related programs. In no event shall such costs be deemed Section 376-eligible or be determined to displace CTC. The Parties agree that SCE will not record such costs in the TRA or other cost recovery accounts, nor will SCE be obligated to start making such expenditures until a Commission decision or resolution has addressed SCE's application or advice letter.

The Parties agree the Commission should be guided by examples as outlined here. The Parties agree, for example, that if a new, substantial Customer Education Program were to occur, that program would satisfy the criteria for a substantial event. As a further example the Parties agree that a Commission requirement for SCE to verify all direct access service requests would satisfy the criteria for a substantial event. The Parties agree that this section shall not apply to minor (*i.e.*, not substantial) revisions to existing restructuring-related programs.

I. Further Reviews And Adjustments

The Parties agree that EMCs are not subject to further reasonableness reviews. The Parties further agree that SCE will continue to track IMC expenditures according to the IRMA accounts already established by the Commission and report these expenditures, by account, on an annual basis to ORA. The expenditures will be reported in a letter to the Director or Acting Director of ORA with copies to the Managers of: (1) the Monopoly Regulation Branch; (2) the Market Development Branch; and, (3) the Consumer Issues Branch. The letter should be mailed by April 30th of each year and will also contain a running total of dollars expended by account, per annum, since 1997. The first letter would be due April 30, 2000 and would contain three years of data (for 1997, 1998, and 1999), the next letters would be due April 30, 2001, April 30, 2002, and, if revenue requirement is still being collected for these IMC's in 2002 a further letter on April 30, 2003. These reporting requirements may be terminated at ORA's discretion.

Other than as provided in this section, the Parties also agree that IMCs are not subject to further investigation, review, reasonableness review, adjustment, true-ups between actual and forecasted (or estimated) costs or reconciliations of any nature.

V.
ADDITIONAL TERMS AND CONDITIONS

A. Term Of Settlement Agreement

The Parties agree that for purposes of determining the CTC Displacement Amount and recovery of IMCs and EMCs, this Settlement Agreement shall be in effect until such costs are determined as of December 31, 2001.

B. Obligation To Promote Approval

The Parties agree to use their best efforts to propose, support and advocate adoption of this Settlement Agreement by the Commission. The Parties agree to perform diligently, and in good faith, all actions required or implied herein, including, but not necessarily limited to, the execution of any other documents required to effectuate the terms of this Settlement Agreement, and the preparation of exhibits for, and presentation of witnesses at, any required hearings to obtain the approval and adoption of this Settlement Agreement by the Commission. No Party to this Settlement Agreement will contest any aspect of this Settlement Agreement in any proceeding or in any other forum, by contact or communication, whether written or oral (including *ex parte* communications whether or not reportable under the Commission's Rule of Practice and Procedure) or in any other manner before this Commission.

The Parties further agree that they will use reasonable efforts to provide notice to the other parties that they intend to enter into *ex parte* discussions with any Commission decision-maker regarding the recommendations contained in this Settlement Agreement, whether reportable under the Commission's Rules of Practice and Procedure, or not. Moreover, the Parties agree to actively and mutually defend this settlement if its adoption is opposed by any other party to the proceeding. The Parties understand and acknowledge that time is of the essence in obtaining the Commission's approval of this Settlement Agreement and that each

Party will extend its best efforts to ensure the adoption of this Settlement Agreement.

C. Public Interest

The Parties agree jointly by executing and submitting this Settlement Agreement that the relief requested herein is just, fair and reasonable, and in the public interest. Each of the Parties actively participated in the settlement process, with substantiation of its position.

D. Non-Precedential Effect

This Settlement Agreement is not intended by the Parties to be a binding precedent for any future proceeding. The Parties have assented to the terms of this Settlement Agreement only for the purpose of arriving at the various compromises embodied in this Settlement Agreement. Each Party expressly reserves its right to advocate, in current and future proceedings, positions, principles, assumptions, arguments and methodologies which may be different than those underlying this Settlement Agreement and the Parties expressly declare that, as provided in Rule 51 of the Commission's Rules of Practice and Procedure, this Settlement Agreement should not be considered as a precedent for or against them.

E. Indivisibility

The Parties acknowledge that the positions expressed in this Settlement Agreement were reached after consideration of all positions advanced by each of the Parties during the settlement negotiations. This Settlement Agreement embodies compromises of the Parties' positions. No individual term of this Settlement Agreement is assented to by any Party except in consideration of the Parties' assents to all other terms. Thus, the Settlement Agreement is indivisible and each part is interdependent on each and all other parts.

Any Party may withdraw from this Settlement Agreement if the Commission modifies, deletes from, or adds to the disposition of the matters stipulated herein. The Parties agree, however, to negotiate in good faith with regard to any

Commission-ordered changes in order to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful.

F. Liability

The Parties further agree that no signatory to this Settlement Agreement, nor any member of the Staff of the Commission, assumes any personal liability as a result of this Settlement Agreement.

G. Governing Law

This Settlement Agreement shall be governed by the laws of the State of California (without regard to conflicts of law principles) as to all matters, including, but not limited to, matters of validity, construction, effect, performance and remedies.

H. Interpretation

The section headings contained in this Settlement Agreement are solely for the purpose of reference, are not part of the agreement of the Parties, and shall not in any way affect the meaning or interpretation of this Settlement Agreement. All references in this Settlement Agreement to Sections are to Sections of this Settlement Agreement unless otherwise indicated. Each of the Parties hereto and their respective counsel have contributed to the preparation of this Settlement Agreement. Accordingly, no provision of this Settlement Agreement shall be construed against any Party because that Party or its counsel drafted the provision.

I. No Waiver

It is understood and agreed that no failure or delay by any Party hereto in exercising any right, power or privilege herein shall operate as a waiver thereof, nor shall any single or partial exercise thereof preclude any other or future exercise thereof or the exercise of any other right, power or privilege.

J. Amendment/Severability

This Settlement Agreement sets forth the entire understanding and agreement between the Parties with reference to the subject matter hereof, and this Settlement Agreement may not be modified or terminated except by an instrument in writing signed by all Parties hereto. This Settlement Agreement supersedes all prior agreements, negotiations, and understandings among the Parties, both oral and written related to this matter.

K. Counterparts

This Settlement Agreement may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

M. Execution

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

Bruce C. Foster

BRUCE C. FOSTER

Vice President,
Southern California Edison Company
601 Van Ness Ave.
San Francisco, CA 94102
(415) 775-1856
(415) 474-3080 (facsimile)

May 13, 1999

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

W. Scott Cauchois

W. SCOTT CAUCHOIS

Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
(415) 703-1525
(415) 703-1981 (facsimile)

May 13, 1999

ATTACHMENT 1

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

William H. Booth

WILLIAM H. BOOTH

Attorney for:
California Large Energy Consumers Assoc.
Law Offices of William H. Booth
1500 Newell Ave., 5th Floor
Walnut Creek, CA 94596
(925) 296-2460
(925) 296-2464 (facsimile)

May 13, 1999

ATTACHMENT 1

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

Michael P. Alcantar
MICHAEL P. ALCANTAR

Attorney for:
California Association of Cogenerators
Alcantar & Elsesser LLP
1300 SW Fifth Avenue – Suite 1750
Portland, OR 97201
(503) 402-9900
(503) 402-8882 (facsimile)

May 13, 1999

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

Evelyn Kahl Elsesser

EVELYN KAHL ELSESSER

Attorney for:
Energy Producers and Users Coalition
Alcantar & Elsesser LLP
One Embarcadero Center - Suite 2420
San Francisco, CA 94111
(415) 421-4143
(415) 989-1263 (facsimile)

May 13, 1999

ATTACHMENT 1

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

ROBERT FINKELSTEIN

Attorney for:
The Utility Reform Network
711 Van Ness Ave, Ste. 350
San Francisco, CA 94102
(415) 929-8876
(415) 929-1132 (facsimile)

May 13 1999

ATTACHMENT 1

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

Keith R McCrea

KEITH R. MCCREA

Attorney for:
The California Manufacturers Association
Sutherland, Asbill & Brennan, LLP
1275 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2404
(202) 383-0705
(202) 637-3593 (facsimile)

May 14, 1999

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

RONALD LIEBERT

Attorney for:
The California Farm Bureau Federation
2300 River Plaza Dr.
Sacramento, CA 95833
(916) 561-5657
(916) 561-5691 (facsimile)

May 17, 1999

ATTACHMENT 1

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

TRACI GRUNDON

Attorney for,
University of California and California State University
Grueneich Resource Associates
582 Market Street, Suite 1020
San Francisco, CA 94104
(415) 834-2300
(415) 834-2310 (facsimile)

May 18, 1999

In witness whereof, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

DAN L. CARROLL

Attorney for:
The California Industrial Users
555 Capitol Mall, 10th Floor
Sacramento, CA 95814
(916) 441-0131
(916) 441-4021

May 18 1999

(END OF ATTACHMENT 1)

A.98-05-004 et al.
D.99-09-064

Commissioner Josiah L. Neeper, Concurring:

Today's Decision modifies the settlement between ORA and Southern California Edison (SCE) because, per AB 1890, certain costs incurred during the rate freeze cannot be deferred to after the rate freeze ends. I am writing this concurring opinion in order to explain my understanding of what happens to those costs incurred during the rate freeze period. Specifically, I want to point out that it may be necessary to extend the end date of the rate freeze under certain circumstances. Though extending the rate freeze is not desirable, I believe it is important to lay out the specific mechanisms so there is no confusion later.

SCE may incur unexpected costs before and close to the expected date for the rate freeze to end. Assuming these costs are appropriate for recovery during the rate freeze period, SCE will have to carefully calculate the date the rate freeze ends according to the method discussed in this Decision, and may need to extend the rate freeze for some period of time. The exception is when legitimate costs would push the end of the rate freeze past the statutory limit of December 31, 2001 or March 31, 2002 (depending on circumstances); in this case, SCE will neither have an opportunity to extend the rate freeze nor to collect the costs after the rate freeze ends.

Of course, it is also possible that the rate freeze will end earlier than predicted. SCE's exercise in calculation should provide for the rate freeze to end on the earlier day that all of the criteria in this Decision are satisfied.

JOSIAH L. NEEPER
Commissioner

San Francisco, California
September 16, 1999