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Decision 99-05-031 May 13, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

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 Appendix A for list of appearances.)

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INTERIM OPINION REGARDING PUBLIC UTILITIES CODE SECTION 376 AS APPLIED TO PACIFIC GAS AND ELECTRIC COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY

Summary

In this decision, we consider the settlement proposals presented to us by Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) regarding issues related to restructuring implementation costs to which Pub. Util. Code § 376[1] treatment applies. We will approve the settlements as being reasonable in light of the whole record, consistent with the law, and in the public interest.

Procedural History

In Decision (D.) 97-11-074, we ordered Southern California Edison Company (Edison), PG&E, and SDG&E to file applications to identify restructuring implementation costs incurred under § 376. On May 1, 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 the Office of Ratepayer Advocates (ORA); Enron; jointly by the California Association of Cogenerators (CAC) and the Energy Producers and Users Coalition (EPUC); jointly by the California Manufacturers Association (CMA), the California Large Energy Consumers Association (CLECA), and the California Industrial Users (CIU). PG&E, Edison, and SDG&E replied to these protests. PG&E, Edison, ORA,

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

[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.

Enron, and The Utility Reform Network (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.

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.

Informal discussions among the parties led to two settlement conferences, in conformance with Rule 51, held in San Francisco on October 23 for PG&E and October 20 for SDG&E. PG&E, ORA, CLECA, CMA, EPUC, and CAC filed a motion for adoption of settlement agreement on November 13. On December 3, PG&E filed a supplement that added CIU and University of California/State University of California (UC/CSU) as signatories to the proposed settlement. On November 12, SDG&E, ORA, Federal Executive Agencies (FEA), CMA, CLECA, CAC, EPUC, and UC/CSU filed a motion for adoption of settlement agreement. Enron and TURN filed comments contesting PG&E's proposed settlement. Enron also contested SDG&E's settlement. Evidentiary hearings on the contested issues in the settlements were held on January 4 and 6, 1999. Commissioner Bilas attended the closing arguments on January 13. PG&E's and SDG&E's applications were submitted upon reply briefs filed on February 18, 1999, respectively. PG&E, ORA, CLECA, CMA, and CIU filed joint opening and reply briefs, as did SDG&E, ORA, CMA, CLECA, and FEA. Edison, TURN, and Enron also filed opening and reply briefs. ORA also filed a separate reply brief. The principal hearing officer completed and issued the proposed decision on a timely basis, 21 days after submission.

Comments on Proposed and Alternate Decisions

In comments to Commissioner Neeper's alternate decision in this matter, PG&E and TURN indicated that TURN now supports the adoption of PG&E's settlement agreement. Therefore, TURN has subsequently become a party to the PG&E settlement agreement and withdrawn its conditional opposition to that settlement. We have modified the proposed decision to address this information and to incorporate, as appropriate, comments filed by the parties.[3] As required by Rule 77.3, we have given no weight to comments that merely reargue positions taken in brief. Instead, we have focused on the factual, legal, or technical errors pointed out by the parties.

In comments to Commissioner Neeper's alternate decision, PG&E and TURN have clarified the treatment of incremental restructuring-related costs. Parties now agree that PG&E will voluntarily withdraw from its General Rate Case (GRC) the incremental restructuring-related costs that were included in its base rate request (as identified in GRC Exhibit 418). Instead, PG&E will seek to recover these costs through the Electric Restructuring Costs Account (ERCA). Based on these clarifications, we can adopt both PG&E's and SDG&E's settlement agreements.

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[3] PG&E, SDG&E, Edison, ORA, TURN, Enron, CLECA and CMA, and Joint Parties to PG&E's Settlement filed opening comments on the proposed decision. PG&E, SDG&E, ORA, TURN, Enron, Farm Bureau, and University of California/California State University filed reply comments.

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.)

PG&E's Proposed Settlement

PG&E 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 PG&E can claim for § 376 treatment, i.e., amounts that might lead to an extension of transition cost recovery after the rate freeze ends.

Under the proposed settlement, costs would be separated into two categories. Externally managed restructuring costs consist of FERC-approved ISO and PX start-up and development costs and Commission-approved consumer education program costs. Internally managed restructuring costs consist primarily of the costs of direct access implementation and demand PX bidding and settlement systems. The settlement proposes that 1) only externally managed costs be eligible for § 376 treatment, 2) these costs are fully recoverable, and 3) PG&E agrees to cap this treatment at $95 million, i.e., to the extent that recovery of externally managed costs displace generation-related transition cost recovery by December 31, 2001, only $95 million will be recovered in the post-transition period.

The settling parties agree that PG&E will waive § 376 treatment of all internally managed implementation costs, including all such costs included in its 1999 General Rate Case (GRC) application (A.) 97-12-020. These costs consist primarily of the costs of direct access implementation and demand PX bidding and settlement systems. For 1997 and 1998, the settling parties agree that 1997 and 1998 internally managed costs are recoverable, but that PG&E will forgo $10 million or approximately 20% of the internally managed costs for 1997 and 1998.

The proposed settlement recommends that generation-related restructuring expense will be eligible for recovery through the Transition Cost Balancing Account (TCBA) mechanism, specifically through the non-must-run and must-run memorandum accounts as going forward costs. Therefore, these costs are not treated as transition costs, but as costs of operating in the market. Generation-related capital costs would either be recoverable in this fashion or as capital revenue requirements based on the results of PG&E's capital additions proceeding, A.98-07-058.

The settling parties propose that the externally managed costs and the internally managed costs be recovered through the Transition Revenue Account (TRA), with cost allocation and verification of entries considered in the Revenue Allocation Proceeding (RAP), A.98-07-006, et al.

The settlement recommends that a new account be established. The Electric Restructuring Costs Account (ERCA) would have two purposes: 1) to allow for the recording and recovery of unanticipated restructuring costs not forecast in PG&E's 1999 GRC and 2) to require the Commission to consider the costs of new restructuring programs before it requires the utilities to incur the costs. Finally, the settling parties propose that PG&E can track in ERCA any costs incurred in its role of scheduling coordinator for municipal utilities and governmental agencies under pre-existing wholesale transmission service contracts which FERC does not allow PG&E to pass on to the contract holders. In effect, this issue is deferred to some future proceeding. Parties take no position on the reasonableness of these costs and reserve the right to oppose any future PG&E request for recovery of these costs.

The parties contend that the settlement is in the public interest and reaches a fair compromise of the disputed issues in this proceeding. The settling parties believe that the public interest is served by establishing three simple eligibility principles and by resolving the reasonableness and recovery issues. For 1997 and 1998, PG&E expects to incur $114.3 million in restructuring implementation expensed costs and $11.6 million in capital costs, for a total of $125.9 million. Out of this total, PG&E has subtracted $13.6 million for which it expects to seek recovery in other forums, externally managed costs of $62.2 million for 1997 and 1998, and a settlement reduction of $10 million. This results in a total of $40.065 million, to which is added $1.2 million in interest and franchise fees and uncollectible expenses (FF&U), for a revenue requirement of $41.279 million in internally managed costs to be recovered through the TRA for 1997 and 1998. PG&E states that it expects to overspend its 1998 estimates by several million dollars. Parties agreed to settle based on the forecast amount, because these forecasts were based on several months of recorded data and the forecast amount would discipline PG&E's expenditures for the remainder of the year. Externally managed costs would continue to be recovered through the TRA on a recorded basis throughout the transition period.

Parties also contend that the settlement is in the public interest because it identifies and addresses the overlap issues with other proceedings and provides a clear roadmap for their resolution. Parties believe that close coordination is required between this proceeding and the GRC. Originally, parties proposed that the Commission determine in the GRC that such implementation costs should be removed from base rates in the GRC, then these costs would be eligible for recording in the ERCA. As discussed above, parties now agree that PG&E will withdraw the incremental restructuring related costs that were included in its GRC, A.97-12-020 (as identified in GRA Exhibit 418), and will seek recovery through the ERCA. Cost allocation and recovery of implementation costs found reasonable in this proceeding will be addressed in the RAP. The settling parties also propose that recovery of the generation capital additions costs for 1997 and 1998 will be addressed in A.98-07-058, PG&E's capital additions proceeding. Recovery of the costs of Western Power Exchange (WEPEX)-related projects for 1998 will be addressed at FERC and recovered in the transmission revenue requirement. Finally, the settling parties recommend that recovery of expenses related to the generation settlement, billing, and bidding systems for 1997 and 1998 would be recovered as generation going forward costs in 1998 through the TCBA's memorandum accounts. Review of these costs will be addressed in the 1999 Annual Transition Cost Proceeding (ATCP).

SDG&E's Settlement

SDG&E's proposed settlement defines externally managed costs (EMCs) as the actual amounts expended for the PX initial charge, the start-up and development portion of the ISO grid management charge, and the Consumer Education Program and Electric Education Trust costs. Upon approval of the proposed settlement, these EMCs would be deemed to be funded by SDG&E and recoverable from customers pursuant to § 376.

SDG&E defines internally managed costs (IMCs) as direct access implementation costs, PX load bidding and demand settlement costs, ISO/PX interfaces, hourly interval meter installation and reading costs, utility distribution company (UDC) billing systems modification costs, customer information release system costs, and environmental impact report costs. The settlement proposes to fix the revenue requirement for these costs at $35.7 million. The settlement proposes that § 376 IMCs are the portion of IMCs which is eligible to displace generation-related transition cost recovery during the transition period and is fixed at $16.8 million (41.7% of total IMCs). The total amount of transition costs that could be displaced by § 376 recovery is defined as the EMC amount plus the fixed § 376 IMC amount. The settling parties agree that SDG&E should be authorized to recover the full, actual amount of EMCs on a dollar-for-dollar basis. Parties predict that EMCs will total approximately $32.5 million from 1997 - 2001.

In A.98-01-014, SDG&E's distribution PBR proceeding, SDG&E and various parties agreed in a settlement agreement related to SDG&E's 1999 cost of service study, that certain specified costs should be considered for recovery in this proceeding. The settling parties to this proceeding agree that these costs are reflected in the IMCs and are recoverable. Parties further agree that the cost recovery mechanism for IMCs should continue through the later of the end of 2002 or the Commission's resolution of SDG&E's next cost of service study, to be filed no later than December 21, 2001.

The settling parties propose that SDG&E file an annual advice letter to establish the rate recovery for the IMC and EMC revenue requirements. The parties state that these costs, except for those costs covered by the ISO grid management charge, are not currently recovered in SDG&E's rates and are not to be included in SDG&E's distribution rate. SDG&E proposes establishing a Consolidated Restructuring and Section 376 account, with subaccounts of Internally Managed Cost Account (IMCA) and Externally Managed Cost Balancing Account (EMCBA). The settlement proposes that separate rate components be set annually through the end of 2002 for the IMCA revenue requirement and through the end of 2001 based initially on the EMCBA revenue requirement, which represents a forecast of projected EMCs not recovered elsewhere in FERC or Commission rates. If SDG&E's request to establish a TRA is approved in the RAP proceeding (A.98-07-006, *et al.*), the total of the billed revenues recorded in the Consolidated Restructuring and Section 376 Account will be transferred to the TRA.

On a monthly basis, SDG&E proposes to compare billed revenues from the EMC rate component to actual EMCs. Any over- or under-collection resulting from this comparison will be reflected in the subsequent year's EMC rate component and would receive the three-month commercial paper interest rate. The rate set to cover EMCs and IMCs for calendar year 1999 would recover EMCs forecasted for 1999 as well as recorded costs for 1997 and 1998. The parties also agree that the methodology for determining revenue fluctuations due to sales will be consistent with the methodology adopted in D.98-12-038 regarding SDG&E's cost of service settlement in A.98-01-014.

The settlement proposes that SDG&E track the total amount of EMCs and 376 IMCs in a new "Competition Transition Charge (CTC) Displacement Tracking Account" and to compare the total to the TCBA to evaluate SDG&E's reduced opportunity to recover its transition costs.

The EMCs are not subject to further reasonableness reviews. SDG&E agrees to track its IMCs during the transition period until such time as ORA indicates to SDG&E that such tracking is no longer necessary. However, the IMCs are not subject to further review, investigation, and adjustment.

The settlement also defines "substantial future regulatorily required restructuring costs" as those costs for new restructuring-related programs that represent a substantial departure from the current restructuring-related programs. These costs would be imposed by either a FERC or Commission decision and must amount to costs of $1 million or more in annual revenue requirements for programs lasting longer than one year, or $2 million or more in revenue requirements for a single "restructuring-related, ISO, or PX program." (SDG&E settlement, p. 8.)

TURN's Position

TURN initially opposed PG&E's settlement. As indicated above, TURN has subsequently become a party to the settlement and withdraws its conditional opposition.

Enron's Position

Enron believes functionalization, or cost assignment to particular services or function, 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. Because neither the PG&E nor the SDG&E settlement recommends functionalization of restructuring implementation costs, Enron recommends that the settlements be rejected, in part.

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 PG&E's recovery of IMCs through a one-time debit to the TRA and recovery of approved EMCs through monthly debits to the TRA. 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.

Similarly, Enron contends that SDG&E's cost recovery mechanism does not reflect established Commission policy. SDG&E proposes to establish two separate rate components based on IMC and EMC revenue requirements, to be set annually and to remain in effect through the end of the year 2002 (IMC) and 2001 (EMC). These separate rate components will be assessed on all customers for recovery and, therefore, Enron contends that this settlement does not comply with Commission policy. The revenue requirements for these rate components would be subtracted from total billed revenues prior to the determination of CTC residual revenues.

Enron also contends that SDG&E's proposed recovery of IMCs raises issues of statutory interpretation, because the proposed settlement provides for recovery of IMCs in part on a forecasted basis. Thus, it is not clear that the costs have met the § 376 hurdle of being funded by an electrical corporation. The settlement's proposed recovery of EMCs may lead to double recovery because of the inclusion of start-up and development portion of the ISO grid management charge. Enron believes this charge is already recovered as average PX revenues in the PX charge assessed to SDG&E's bundled service customers.

Enron proposes that its functionalization proposal be reflected in customers' rates by increasing the PX credit for 1997 and 1998 costs for the procurement function. Enron believes this true-up would be similar to the true-up to the PX charge or credit currently calculated by the UDCs in order to correct inaccuracies. Enron contends that the absence of language regarding functionalization in § 376 does not preclude such a means of recovery. Moreover, Enron argues that its position in the RAP pertains solely to procurement costs, particularly which procurement costs currently embedded in the UDCs' rates as well as ongoing costs of procurement should be reflected in the PX credit. Enron explains that its proposal in the RAP does not address the other five functional categories it has developed here for the UDCs' restructuring implementation costs.

Edison's Position

Edison's briefs are limited to one issue: ORA's benchmarking proposal for reasonableness reviews as described in Exhibit 34. In that proposal, ORA recommends that, to determine reasonable forecasts of future costs, each utility be required to provide data in a common format and to provide testimony comparing itself to the other two utilities and explaining why it was necessary to exceed the lowest-cost utility in three program areas: direct access implementation, hourly interval meters, and billing system modifications. Edison disputes the efficacy of this proposal and believes it is unworkable. ORA recommends that Edison's brief be accorded no weight, as the issue was fully litigated in Phase 1 of the Edison phase of this proceeding.

We are satisfied that the showing we will require for reasonableness review purposes will be adequate in forming a record, without requiring comparison among utilities, either on an actual or forecast cost basis.

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." These cases are close to all-party settlements. No party opposes either settlement.

TURN and ENRON provide comments on the two settlements. The settlements enjoy the support or lack of opposition of representatives of all active parties. However, technically all active parties in this proceeding do not sponsor the settlements. While we could consider these settlements under the all-party settlement rules (and would find them to be in the public interest under that criteria), instead we will consider the settlements under the criteria set forth in Rule 51.1(e). 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.)

We believe that the settlements before us are reasonable in light of the whole record, consistent with the law, and in the public interest. We do not agree with TURN that Commission policy should always be consistent across utilities in the same industry, even in these proceedings where we are implementing a specific statute. It would be reasonable to adopt particular standards for Edison but different standards for PG&E and SDG&E if the settlements are reasonable and in the public interest on their own merits.

TURN's recommendation that Commission policy should be consistent across utilities in this case is not adopted. TURN also originally recommended that costs associated with the implementation of direct access, the ISO and the PX should not be included in rates for test year 1999. We will adopt PG&E's proposal to establish an Electric Restructuring Costs Account (ERCA), and are pleased that PG&E has withdrawn its alternative proposal to place such costs in base rates to PG&E's pending general rate case. Adoption of the ERCA does not allow PG&E to recover these costs in distribution rates. PG&E will need to file a new application to seek recovery of these costs.

ENRON proposes that the settlements 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, this issue is pending in the Revenue Adjustment Proceeding for each utility, and may be considered in that case or elsewhere.

Below we discuss the specifics of the settlements. First, we will articulate principles related to cost recovery. Next, we adopt general guidelines regarding §376 treatment and cost recovery. After that, we discuss the settlements in terms of conformance with the adopted guidelines.

Implementation of the new market structure has occurred as of December 31, 1998

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.

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. Simply because an activity is not eligible for 376 treatment because we reached the conclusion that it is not an implementation activity, does not constitute that the reasonable costs associated with that activity are not recoverable. Since many of these costs are incurred to comply with specific orders of this Commission, we have to provide mechanisms for recovery. 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 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.
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> "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.
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> "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.)

Restructuring-related costs Are Found to be Recoverable

Costs incurred by PG&E or SDG&E that have been expended on approved restructuring-related activities should be recoverable from customers. Costs expended by PG&E or SDG&E to carry out many Commission-mandated restructuring related programs are also recoverable in rates. We must carefully evaluate costs to determine if the utilities incurred particular costs 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 as a distribution utility, or 3) in compliance with other Commission requirements related to restructuring (for example, carry out the mandates of Rule 22 and Rule 25, as required by the Commission or the obligations in providing service to consumers that do not elect direct access). Costs expended to operate as a distribution utility may be recovered through a separate rate component or the TRA as a distinguishable cost component. Costs related to each of these categories are recoverable but only those in the first category are eligible for § 376 treatment consistent with our Adopted Guidelines.

We recognize that the utilities may expend significant costs in carrying out Commission mandates to facilitate competitive market development. 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, costs of competing in the new competitive generation marketplace; i.e., costs the utility expends to compete voluntarily in the marketplace on price, terms and conditions determined by the utility, shall be recovered in wholesale or retail markets as appropriate.

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. Neither PG&E nor SDG&E should seek to recover such costs as employee transition costs, to the extent personnel who would otherwise have worked on discontinued functions staff new activities.

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.[4]

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. As we determined in our accompanying decision in this docket, we will not further functionalize restructuring implementation costs at this time. We have adopted stringent criteria for allowing § 376 treatment of restructuring implementation costs. As delineated herein, these costs have been incurred to create the new market structure. 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.

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[4] We will not address the issue of fees for DASR processing or fees for discretionary services. Pursuant to an Assigned Commissioner's Ruling issued on February 5, 1999, in R.94-04-031/I.94-04-032, PG&E, Edison, and SDG&E are ordered to file applications on April 30, 1999 to address such fees.

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."

PG&E's request to recover eligible costs in the TRA is reasonable. Given our Adopted Guidelines in this proceeding, there is no need to track IMCs beyond 1998 for §376 treatment purposes.

We recognize that SDG&E's request to establish a TRA in the RAP was granted. SDG&E shall recover eligible implementation costs in the same fashion as PG&E. Both PG&E and SDG&E should record these § 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. As we discuss below, § 376 treatment should not be triggered for SDG&E provided that it is able to end the rate freeze and transition cost recovery as early as it has proposed in A. 99-02-029.

Once final costs are approved for § 376 treatment, revenues should be allocated to these costs according to the principles established in the RAP, A.98-07-006, *et al.*

Adopted Guidelines

These are our adopted 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.

8. 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.

9. Restructuring-related reasonable program costs should be recoverable from all ratepayers. The costs of services voluntarily offered by the utility at prices, terms and conditions determined by it in a manner similar to other market participants may be recovered only through wholesale or retail markets as appropriate.

10. 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.

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

12. 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).

13. 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.

Proposed Settlements and Conformance with Adopted Guidelines

In this section, we address the proposed settlements and consider whether these proposed agreements conform to our Adopted Guidelines. When this proceeding began, the Assigned Commissioner encouraged the parties to attempt to achieve settlement. PG&E, SDG&E and a significant large group of participants took that suggestion seriously and they in fact achieved a settlement. We appreciate those parties for this effort. These settlements are found for be reasonable, in the public interest and consistent with the Adopted Guidelines established in this decision.

The externally managed costs that are discussed in both PG&E's and SDG&E's settlements allow § 376 treatment and cost recovery for ISO and PX start-up and development costs, CEP costs, and EET costs. This approach is consistent with the Adopted Guidelines. We determined that these costs are eligible for § 376 cost recovery, and should be presumed reasonable.

Consistent with the proposed settlements, we agree that PG&E's and SDG&E's shares of both the ISO and PX start-up and development costs are eligible for § 376 treatment. 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. 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 (see § 392(b))[5] 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

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[5] 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.

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 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 both the PG&E and SDG&E settlements.

The IMC costs recommended for § 376 treatment in the proposed settlements comport with our Adopted Guidelines; the proposed cost recovery of IMCs also complies with those guidelines.

This decision establishes our Adopted Guidelines that show that direct access costs are eligible for § 376 treatment only to the extent these costs are required to implement the program through December 31, 1998, with the exception of the uniform node identifier system (UNIS) costs.

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.[6] 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.

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

We determined that these cost categories were too broad to distinguish which specifically could be attributed to implementation of direct access, but 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 also allow that pre-1999 costs are recoverable by the utility from all customers. We find that the settlement agreements are consistent with our Adopted Guidelines in this decision. 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, SDG&E's settlement provides for cost recovery for EMCs and IMCs through 2001 and 2002, respectively, and a provision that entitles SDG&E to recover "substantial future regulatorily required restructuring costs." We approve these provisions.

The settlement by PG&E provides for an Electric Restructuring Cost Account (ERCA): 1) allows the recording and recovery of unanticipated restructuring costs not forecast in PG&E's 1999 GRC and 2) requires the Commission to consider the costs of new restructuring programs before PG&E can incur the costs. The settling parties also propose that PG&E track in ERCA any costs expended in its role as scheduling coordinator for municipal utilities and governmental agencies under pre-existing wholesale transmission service contracts which FERC may not allow PG&E to pass on to the contract holders. Consistent with PG&E's settlement, the costs associated with these contracts tracked in ERCA may be recovered through a separate application. We approved these provisions. However, the costs of competitive services utility voluntarily offered by setting prices, terms and conditions similar to other market competitors must be recovered through the wholesale and retail markets as appropriate.

Voluntary Cap

We allow and approve the voluntary caps on the amounts that will be eligible for transition cost recovery after the transition period contained in PG&E's and SDG&E's settlements.

Impact of A.99-02-029

On February 19, SDG&E filed A.99-02-029, informing the Commission that it expects to have completed full recovery of Commission-authorized costs for utility generation-related assets and obligations as early as June 30, 1999, thereby meeting the statutory condition for termination of its electric rate freeze. For SDG&E, if this event takes place, it is clear that none of the restructuring implementation costs need be given § 376 treatment, i.e., recovery of these costs obviously will not displace recovery of generation-related transition costs. However, as shown above, SDG&E's proposal for cost recovery, as contained in its settlement, is hereby approved.

In this decision, we adopt guidelines for costs eligible for § 376 treatment and cost recovery. PG&E's and SDG&E's settlements are consistent with these Adopted Guidelines.

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.98-05-004 and A.98-05-006, PG&E and SDG&E, respectively, seek to establish the eligibility of particular cost categories for which § 376 treatment is appropriate and the applicable ratemaking and rate recovery mechanisms.

3. On November 13, 1998, PG&E 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. On November 12, 1998, SDG&E and various parties filed a Motion for Adoption of Settlement that would resolve Phase 1 eligibility and Phase 2 reasonableness issues in this proceeding.

5. Both proposed settlements would separate costs into externally managed restructuring costs and internally managed restructuring costs.

6. 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.

7. PG&E's internally managed costs consist of the costs of direct access implementation and demand PX bidding and settlement systems.

8. PG&E's settlement proposes that only externally managed costs are eligible for § 376 treatment. PG&E agrees to cap this treatment at $95 million.

9. PG&E proposes to waive § 376 treatment for all internally managed implementation costs, including those costs requested in the 1999 GRC proceeding, A.97-12-020.

10. Parties agree that PG&E's 1997 and 1998 internally managed costs are recoverable through the TRA and cap this amount at $41.3 million.

11. PG&E's settlement recommends establishing the ERCA to allow for the recording and recovery of unanticipated restructuring costs not forecast in the GRC, to track any unrecovered costs associated with PG&E's wholesale contracts that FERC does not allow PG&E to recover from the contract holders, and to

require the Commission to consider the costs of new programs before ordering the utilities to incur these costs.

12. SDG&E'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, customer information release system costs, and environmental impact report costs. The settlement proposes to fix the revenue requirement of these costs at $35.7 million, $16.8 million of which would be granted § 376 recovery.

13. D.98-12-038 adopted a cost of service settlement in SDG&E's PBR proceeding, A.98-01-014. Parties propose that costs related to direct access O&M costs and rate base additions, which were deferred to the instant proceeding, be recovered in this proceeding.

14. Parties propose that SDG&E establish separate rate components to recover the IMC and EMC revenue requirements through the end of 2002 and 2001, respectively.

15. TURN has subsequently become a party to PG&E's settlement and withdraws its conditional opposition to that settlement.

16. Enron contests both PG&E's and SDG&E's settlements, because neither settlement includes functionalization of restructuring implementation costs.

17. 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.

18. Allowing §376 treatment for the costs PG&E and SDG&E 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.

19. We will carefully evaluate costs 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 (e.g., carry out the mandates of Rule 22 and Rule 25, as required by the Commission or the obligations inherent in providing service to consumers that do not elect direct access).

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

21. The utilities continue to incur costs to comply with Commission-mandated direct access requirements. The utilities must have an opportunity to recover these costs. SDG&E and PG&E may recover restructuring implementation cost and restructuring related costs as set forth in their settlement agreement.

22. Costs the utilities incur to voluntarily participate in the marketplace, setting prices, terms and conditions at their discretion, as do other market competitors shall be recovered from wholesale and/or retail markets as appropriate.

23. 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.

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

25. Only those costs not recovered in any other way may receive § 376 treatment.

26. PG&E's and SDG&E's share of both the ISO and PX start-up and development costs are eligible for § 376 treatment.

27. 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.

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

29. EET costs are eligible for § 376 treatment.

30. 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.

31. 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.

32. 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%.

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

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

35. 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.

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

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

38. Eligible restructuring implementation costs must receive §376 treatment and cost recovery. Only incremental costs may receive § 376 treatment.

39. Avoided costs and associated cost savings must be considered in approving reasonableness.

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

41. 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.

42. 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.

43. We will not further functionalize restructuring implementation costs at this time.

44. We have adopted stringent criteria for allowing § 376 treatment of restructuring implementation costs and these costs have been incurred to create the new market structure.

45. 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.

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

47. 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.

48. Comparison of costs among utilities is not necessary in reviewing reasonableness of eligible costs.

49. SDG&E's A.99-02-029 informs the Commission that SDG&E's rate freeze is expected to end in June 1999. Therefore, § 376 treatment of these costs may not

be relevant; however, cost recovery is still an issue to be independently determined.

Conclusions of Law

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

2. These proceedings were consolidated because they address similar issues of fact and law.

3. 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.

4. If the utilities fully recover their generation-related transition costs before December 31, 2001, § 376 will never be triggered.

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

6. 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.

7. 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.

8. 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.

9. 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.

10. 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.

11. 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.

12. 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.

13. 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.

14. 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.

15. The proposed settlements' treatment of externally managed costs is consistent with our Adopted Guidelines.

16. PG&E's proposed settlement's recommendation to recover externally managed costs through the TRA is reasonable.

17. PG&E's proposed ERCA account is reasonable and should be adopted.

18. SDG&E's proposed ratemaking for recovery of externally managed costs conforms to the guidelines adopted for cost recovery.

19. 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.

20. 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.

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

22. 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.

23. Identification and recovery of all restructuring implementation costs shall be addressed in this proceeding. Restructuring- related costs other than restructuring implementation costs and shall be recoverable, as set forth in PG&E's and SDG&E's settlements.

24. 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.

25. Restructuring implementation costs and restructuring-related costs shall be reviewed for reasonableness. 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 CBP, and the EET are reasonable.

26. PG&E's proposed treatment of internally managed costs is consistent with our Adopted Guidelines, and therefore, its settlement should be approved.

27. SDG&E's proposed treatment of internally managed costs is consistent with our Adopted Guidelines, and therefore, its settlement should be approved.

28. PG&E and SDG&E shall recover restructuring implementation costs deemed eligible for § 376 treatment through a one-time debit entry to the TRA as set forth in their respective settlement agreements.

29. PG&E and SDG&E shall recover restructuring related implementation costs as set forth in their respective settlement agreements.

30. We have long held to the standard that the purchaser or user of a service should bear responsibility for those costs. Similarly, all customers must pay for costs that benefit all customers. It is reasonable to adopt these principles for costs receiving § 376 treatment.

31. Restructuring implementation costs benefit all customers and must be paid for by all customers.

32. Enron's functionalization proposal is rejected in this proceeding.

INTERIM ORDER

IT IS ORDERED that:

1. The motion of Pacific Gas and Electric Company's (PG&E), the Office of Ratepayer Advocates, California Large Energy Consumers Association, California Manufacturers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition, the University of California, the State University of California, and California Industrial Users for Approval of Settlement Agreement, filed on November 12, 1998, is granted.

2. The motion of San Diego Gas & Electric Company (SDG&E), the Office of Ratepayer Advocates, Federal Executive Agencies, California Large Energy Consumers Association, California Manufacturers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition, the University of California, and the State University of California for Adoption of Settlement Agreement on Issues related to San Diego Gas & Electric Company's

Application, A.98-05-006, Under Pub. Util. Code § 376, filed on November 12, 1998, is granted.

This order is effective today.

Dated May 13, 1999, at San Francisco, California

RICHARD A. BILAS
President
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

APPENDIX A
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APPENDIX A
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(END OF APPENDIX A)

ATTACHMENT 1

Settlement Agreement of
PG&E, ORA, CLECA, CMA,
EPUC AND CAC
Regarding Phase 1 and Phase 2 of the
Section 376 Proceeding (A.98-05-004)

November 13, 1998

WHEREAS, On May 1, 1998, Pacific Gas and Electric Company ("PG&E") filed an application with the California Public Utilities Commission ("Commission" or "CPUC") to establish the eligibility and seek recovery of certain electric industry restructuring implementation costs as provided for in Public Utilities Code Section 376. The application was designated A.98-05-004.

WHEREAS, the following entities have intervened in A.98-05-004 and have commented upon and/or protested certain aspects of PG&E's application: Office of Ratepayer Advocates ("ORA"), California Large Energy Consumers Association ("CLECA"); California Manufacturers Association ("CMA"), Cogeneration Association of California ("CAC"), Energy Producers and Users Coalition ("EPUC"), California Industrial Users ("CIU"), California Farm Bureau Federation ("Farm Bureau"), The Utility Reform Network ("TURN") and Enron Corp. ("Enron").

WHEREAS, PG&E, ORA CLECA, CMA, CAC and EPUC (the "Parties") have engaged in settlement discussions and have agreed to settle and fully resolve the issues presented in PG&E's application as specified in this agreement (hereinafter referred to as the "Settlement Agreement") and in accordance with Rule 51 of the Commission's Rules of Practice and Procedure.

NOW, THEREFORE, the Parties hereby agree as follows:

1. This Settlement Agreement, in accordance with Rule 51 of the Commission's Rules of Practice and Procedure, fully resolves the issues associated with PG&E's application in Phase 1 (eligibility) and Phase 2 (reasonableness review and recovery of 1997 and 1998 expenditures) of the Section 376 Proceeding (A.98-05-004). The Parties will fully support and advocate approval of the Settlement Agreement at the Commission. This Settlement Agreement is conditioned upon CPUC approval without modification. If the CPUC approves the Settlement Agreement without modification, a Party will not seek modification of the Commission order approving the Settlement Agreement without the consent of the other Parties.

2. Cost Categories: Restructuring costs will be separated into two categories: "Externally Managed Restructuring Costs" and "Internally Managed Restructuring Costs." Externally Managed Restructuring Costs consist of the costs of (1) FERC-approved ISO and PX start-up and development costs, which excludes ongoing

administrative costs and (2) CPUC-approved consumer education program costs which currently consist of the customer education program ("CEP") and electric education trust ("EET"). Internally Managed Restructuring Costs consist of the costs of all of the other programs incurred in 1997 and 1998 for which PG&E seeks recovery in the Section 376 Proceeding (primarily the costs of direct access implementation, unrecovered existing wholesale contract assessments from the ISO and PX, and demand PX bidding and settlement systems), except the costs for which recovery will be addressed in other proceedings, as listed in paragraph 6 below.

3. Internally Managed Costs: The Parties agree that PG&E may recover in rates during the rate freeze a revenue requirement of $ 41,279,000 reflecting a $10 million revenue requirement reduction from PG&E's filed amounts for 1997 (recorded) and 1998 (projected) of the Internally Managed Restructuring Costs presented in A.98-05-004. The $41,279,000 includes interest and franchise fees and uncollectible expenses through 1998. The $10 million reduction in revenue requirement will be applied to expense items and will not be associated with any specific program. Pending a CPUC decision on allocation of Section 376 costs in the Revenue Allocation Proceeding ("RAP"), PG&E will recover Internally Managed Restructuring Costs, including interest based upon the three month commercial paper rate and franchise fees and uncollectibles expense factor starting January 1, 1999, through a one-time debit entry to the Transition Revenue Account (TRA).

4. Externally Managed Costs: PG&E may fully recover in rates the Externally Managed Restructuring Costs as actually incurred. Pending a CPUC decision on allocation of Section 376 costs in the RAP, PG&E will continue to recover FERC-approved ISO and PX start-up and development costs as incurred through a monthly debit entry to the Transition Revenue Account (TRA). PG&E will recover consumer education program costs, including interest and franchise fees and uncollectibles, through the TRA. Verification of the accuracy of all entries to the TRA will be addressed in the RAP.

5. Section 376 Eligibility of Restructuring Program Costs: Only Externally Managed Restructuring Costs will be eligible for Section 376 treatment (i.e. post-rate freeze recovery of transition costs displaced due to recovery during the rate freeze of these FERC- and CPUC- approved costs). PG&E will track in a memorandum account (PU Code Section 376-Restructuring Implementation Tracking Account, or RITA) only Externally Managed Restructuring Costs . PG&E will waive Section 376 treatment of all Internally Managed Restructuring Costs . PG&E will cap its tracking in RITA of Externally Managed Restructuring Costs at $95 million and will recover no more than $95 million after the rate freeze ends pursuant to Section 376. PG&E may seek recovery of the tracked amount (up to $95 million) in displaced CTC under Section 376 to the extent it does not have sufficient head room to fully amortize its CTC-eligible costs. PG&E will provide to and work with ORA on RITA tariff language to implement the $95 million tracking limit prior to filing it with the Commission.

6. Recovery In Other Proceedings: Recovery of the generation capital additions costs included in A.98-05-004 for 1997 and 1998 will be addressed in the 1997-98 Capital Additions proceeding. (A.98-07-058). Recovery of the costs of WEPEX-related projects for 1998 will be addressed at FERC.

   Recovery of expense related to the generation settlement, billing, and bidding systems ($9.2 million) included in A.98-05-004 for 1997 and 1998 will be withdrawn from this application and recovered as a generation "going forward cost" in 1998. The $9.2 million will be recovered as follows: (1) the costs will be allocated among PG&E's generation on the basis of MW-hours produced by power plants in the 3rd quarter of 1998; and (2) for hydroelectric and geothermal facilities, the costs will be considered incremental to the 1996 GRC-approved O&M.

7. No GRC Precedent: Approval by the Commission of the restructuring implementation program settlement amounts for 1997 and 1998 will establish no precedent nor have any application to the Commission's analysis of the determination of the 1999 forward recovery of restructuring implementation costs included in 1999 General Rate Case ("GRC") -authorized base rates. This settlement has no affect on the Commission's decision in the 1999 GRC, which includes a request for recovery of the revenue requirement for certain restructuring-related capital costs from 1997 and 1998.

8. Coordinated Resolution Of GRC Overlapping Issues: This settlement does not resolve the issue of whether, starting in 1999, PG&E should be authorized to include certain restructuring implementation costs in base rates in its GRC (PG&E's position) or whether such implementation costs should be removed from base rates in the GRC and recovered as incurred, subject to an after the fact reasonableness review (TURN's position). This issue affects both the Section 376 Proceeding and the PG&E GRC and the Parties encourage the Commission to resolve this issue in a coordinated fashion. If the Commission determines in the GRC that such implementation costs should be removed from base rates in the GRC, then recovery of such costs will be addressed in the ERCA mechanism described below.

9. Waiver of Section 376 Treatment for GRC Costs: For the period 1999-2001, PG&E will track in RITA and make eligible for Section 376 treatment only Externally Managed Restructuring Costs as actually incurred during the period. PG&E waives Section 376 treatment, i.e., post-rate freeze recovery, of all costs proposed to be recovered in its GRC-authorized base rates and all post-1998 Internally Managed Restructuring Costs.

10. Unanticipated or Excluded Restructuring Costs: Effective January 1, 1999, PG&E shall establish the Electric Restructuring Costs Account (ERCA) to record and recover restructuring costs incurred to the extent these costs were not forecast in PG&E's 1999 GRC and are the result of the implementation of a new program or

activity prescribed by Commission or FERC order, mandate or requirement or were excluded by the CPUC in the GRC as restructuring costs that should be addressed in another proceeding. (Costs deemed unreasonable in PG&E's GRC will not be eligible for recovery through the ERCA.)

- Recording Costs in the ERCA:

  PG&E shall apply, either by application or advice letter, for prior approval to record costs for those programs which will cost PG&E over $1 million in the 12 months following the date on which PG&E seeks approval. PG&E's request shall include PG&E's estimate of total expenditures and an explanation of why such program was unanticipated or not included in its set of programs presented in A.98-05-004 or its GRC application. PG&E will not record costs in ERCA for such expenditures, nor will it be obligated to start making such expenditures, until a Commission decision or resolution has addressed PG&E's advice letter or application. The protest period associated with a PG&E advice letter filing will be extended from 20 to 30 days.

  Starting January 1, 1999, for programs costing less than $1 million (over a 12 month period), PG&E will not need to seek prior Commission approval before recording costs in the ERCA. PG&E shall, however, apply for authority to record costs either by application or advice letter. PG&E's request shall include PG&E's estimate of total expenditures and an explanation of why such program was unanticipated or not included in its set of programs presented in A.98-05-004 or its GRC application. PG&E shall reverse any ERCA entries if the Commission decision and/or resolution does not explicitly authorize ERCA entries for the program. The protest period associated with a PG&E advice letter filing will be extended from 20 to 30 days.

- Recovering ERCA Costs:

  ERCA balances shall not be afforded Section 376 treatment. That portion of ERCA balances which the Commission finds reasonable and which have been authorized by the Commission will be recoverable in rates. PG&E will seek recovery of costs recorded in the ERCA and allocation of these costs among users of the PG&E system through a separate application or through the Revenue Allocation Proceeding, for which PG&E shall seek a designation of the proceeding as "ratesetting."

11. ISO/PX Charges Assessed To Existing Wholesale Contracts: Commencing January 1, 1999, the ISO Grid Management Charges (ISO GMC) and PX Administrative Charges (PX AC) that are assessed to PG&E as scheduling coordinator for existing wholesale contracts and that PG&E is unable to recover directly from the existing contract holders shall be eligible for recording in ERCA and recovery through ERCA

if found to be reasonable by the CPUC. Approval of this settlement shall constitute CPUC-authorization to record such costs in ERCA. The Parties take no position on the reasonableness of these costs at this time and reserves the right to oppose any future PG&E request for recovery of such costs.

12. Non-Precedential Effect: This Settlement Agreement only resolves PG&E's application in the proceeding and shall not be deemed a precedent with respect to the other investor-owned utilities' applications. In accordance with the CPUC's Rule 51 this Settlement Agreement, or any element of it, shall not be considered a precedent for or against any Party in current and future proceedings.

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

IN WITNESS WHEREOF, intending to be legally bound, the Parties hereto have duly executed this Settlement Agreement on behalf of the Parties they represent.

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ATTACHMENT 2

Schedule 3A
Pacific Gas & Electric Company
Revenue Requirements for Capital Expenditures and Expense Amounts
($ thousands)

Line No.	Category	1997 Expense	1997 Capital	1997 Total	1998 Expense	1998 Capital	1998 Total	1999 Expense	1999 Capital	1999 Total	2000 Expense	2000 Capital	2000 Total	2001 Expense	2001 Capital	2001 Total	1997-2001 Expense	1997-2001 Capital	1997-2001 Total
1	IRMA Subaccounts																		
2	Direct Access Implementation Costs	3,719	-	3,719	3,991	458	4,449	2,525	943	3,468	323	905	1,228	256	776	1,031	10,813	3,082	13,895
3	ISO/PX & Other Wholesale Market Interface Costs																		
4	Electric Supply Settlements System	-	-	-	-	1,057	1,057	-	2,070	2,070	-	1,922	1,922	-	1,816	1,816	-	6,865	6,865
5	Utility Energy Supply Forecast	-	-	-	-	87	87	-	171	171	-	159	159	-	150	150	-	567	567
6	Existing Contractual Obligation Scheduling & Settlements	-	-	-	20	26	46	-	49	49	-	45	45	-	44	44	20	164	184
7	Power System Control Modifications	-		-	-		-	-		-	-		-	-		-	-	-	-
8	Meter Certification	-		-	-		-	-		-	-		-	-		-	-	-	-
9	Generation Revenue Quality Meters	876	46	922	924	2,341	3,265	-	2,846	2,846	-	2,798	2,798	-	2,684	2,684	1,800	10,735	12,535
10	Management of Existing Transmission Contracts	-		-	-		-	-		-	-		-	-		-	-	-	-
11	Generation ISO/PX Settlement, Billing, and Bidding Systems	3,540	(12)	3,528	6,537	474	7,011	1,956	557	2,512	1,830	498	2,328	1,830	452	2,282	14,692	1,969	16,661
12	Western Power Exchange Project	322	-	322	1,563	57	1,620	-	117	117	-	113	113	-	97	97	1,885	384	2,269
13	Existing Wholesale Contracts - ISO Assessment Charge	-		-	3,270	-	3,270	6,120		6,120	6,319		6,319	2,905		2,905	18,614	-	18,614
14	Existing Wholesale Contracts - PX Assessment Charge	-		-	58	-	58	80		80	83		83	86		86	307	-	307
15	ISO/PX & Other Wholesale Market Interface Costs-CIS	490	-	490	206	-	206	213	87	300	-	131	131	-	121	121	909	319	1,228
16	Hourly-Interval Meter Installation & Reading Costs																		
17	Hourly-Interval Meter Reading Costs (Excluding DA DSMA & QF Charges)	8,036	-	8,036	9,337	3,508	12,845	3,756	7,758	11,514	2,891	7,861	10,752	2,980	7,175	10,155	24,012	26,400	50,412
18	Changes to the QF Payment System	-		-	-		-	-		-	-		-	-		-	-	-	-
19	ISO/PX Implementation (Uplift) Costs																		
20	ISO Grid Management Charge	-	-	-	12,075		12,075	16,100		16,100	16,100		16,100	16,100		16,100	60,375	-	60,375
21	PX Assessment Charge	-	-	-	11,349		11,349	11,349		11,349	11,349		11,349	11,349		11,349	45,396	-	45,396
22	PX Volumetric Charge	-	-	-	-		-	-		-	-		-	-		-	-	-	-
23	UDC Billing System Modifications Costs (Excluding DA DSMA)	5,883	7	5,890	5,564	3,336	8,900	3,676	6,873	10,549	1,332	8,310	9,642	1,251	7,913	9,164	17,306	26,439	43,745
24	Customer Information Release Systems Costs	384	-	384	1,001	57	1,058	107	117	224	-	113	113	-	97	97	1,502	384	1,886
25	Consumer Education Program	11,059	-	11,059	23,202	-	23,202	-		-	-	-	-	-	-	-	34,261	-	34,261
26	Electric Education Trust	-	-	-	4,536	-	4,536	1,302		1,302	-	-	-	-	-	-	5,838	-	5,838
27	Environmental Impact Report	538	-	538	-	-	-	-	-	-	-	-	-	-	-	-	538	-	538
28	Total IRMA Subaccounts	31,857	41	31,898	82,633	11,521	94,154	47,185	21,566	68,751	40,227	22,855	63,082	36,766	21,325	58,091	238,468	77,308	315,776
29	DA Discretionary Services Memorandum Account (DSMA)																		
30	DA DSMA for Hourly-Interval Meter Reading Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	DA DSMA for UDC Billing System Modification Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Total DA Discretionary Svcs. Memo. Acct.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	ISO/PX Memorandum Accounts																		
34	ISO Memorandum Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	PX Memorandum Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Total ISO/PX Memo Accounts				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total	31,857	41	31,898	82,633	11,521	94,154	47,185	21,566	68,751	40,227	22,855	63,082	36,766	21,325	58,091	238,468	77,308	315,776
38	CPUC Jurisdictional	31,857	41	31,898	82,633	11,521	94,154	47,185	21,566	68,751	40,227	22,855	63,082	36,766	21,325	58,091	238,468	77,308	315,776
39	Plus: Interest	214	0	214	2,310	0	2,310	1,224	0	1,224	982	0	982	906	0	906	5,646	0	5,646
40	Plus: Franchise Fees & Uncollectibles	310	0	310	858	116	974	489	218	707	416	231	647	380	216	596	2,453	781	3,234
41	Total Revenue Requirements	32,181	41	32,222	85,801	11,637	97,438	48,910	21,784	70,684	41,625	23,086	64,711	38,052	21,541	59,593	246,560	78,089	324,650
42	Net Present Value	257,944																	

Line No.	Comments
	See Schedule 1A comment box. Also see Attachment A for cross reference between schedules.
42	Uses 8% discount rate.

Confidential
Section 376 Phase 1 and Phase 2 Settlement

1997 and 1998 Revenue Requirements ($000) (Fn 1)

Line No.		1997 & 1998 Expense	1997 & 1998 Capital	1997 & 1998 Total	Line No.
1	1997 & 1998 Proposed Revenue Requirements (Fn. 2)	114,290	11,562	125,852	1
	Less Recovery of Costs in Other Forums:				
2	Generation Capital Additions (Fn. 3)		2,869	2,869	2
3	Generation Settle./Billing/Bidding Systems Expense (Fn. 4)	9,077		9,077	3
4	1998 WEPEX (Fn. 5)	1,563	57	1,620	4
5	Total (Lns. 2 to 4)	10,640	2,926	13,566	5
6	Adjusted Amount (Ln. 1 - Ln. 5)	103,650	8,636	112,286	6
	Less Externally Managed Costs:				
7	Consumer Education Program (Fn. 6)	34,261	-	34,261	7
8	Electric Education Trust (Fn. 7)	4,536	-	4,536	8
9	ISO Start-up/Development Costs (Fn. 8)	12,075	-	12,075	9
10	PX Start-up/Development Costs (Fn. 9)	11,349	-	11,349	10
11	Total (Lns 7 to 10)	62,221	-	62,221	11
12	Subtotal (Ln. 6 - Ln. 11)	41,429	8,636	50,065	12
13	Less Settlement Reduction	10,000	-	10,000	13
14	Total (Ln. 12 - Ln. 13)	31,429	8,636	40,065	14
15	Plus Interest & FF&U (3.03%)			1,214	15
16	Total Section 376 Settlement Amount (Lines 14 & 15)			41,279	16

Fn.	Comments
1	Reference document: Schedule 3A of PG&E's June 18, 1998 Prehearing Conference Statement (A. 98-05-004).
2	Source: Line 28 of Schedule 3A.
3	Source: Lines 9 and 11 of Schedule 3A. Recovery will be sought in PG&E's 1997/98 Capital Additions case.
4	Source: Line 11 of Schedule 3A. Recover as "going forward costs" in 1998 through the TCBA memorandum accounts.
5	Source: Line 12 of Schedule 3A. Recovery of 1998 costs will be sought at FERC.
6	Source: Line 25 of Schedule 3A. Recovery of actual costs will be through the TRA.
7	Source: Line 26 of Schedule 3A. Recovery of actual costs will be through the TRA.
8	Source: Line 20 of Schedule 3A. Recovery of actual costs will be through the TRA.
9	Source: Line 21 of Schedule 3A. Recovery of actual costs will be through the TRA.

Oct-15-376.xls

ATTACHMENT 4

REVISED
8/28/98

Pacific Gas & Electric Company
Updated 1998 Costs
Section 376 (A.98-05-004)
($ thousands)

Line No.	Category	Revised Updated 1/1-6/30			Revised Updated 7/1-12/31			Revised Updated Total			Original Estimate (a)			Difference (Revised - Original)		
		Expense	Capital	Total	Expense	Capital	Total	Expense	Capital	Total	Expense	Capital	Total	Expense	Capital	Total
1	IRMA Subaccounts															
2	Direct Access Implementation Costs	2,240	183	2,423	3,171	79	3,250	5,411	262	5,673	3,991	1,211	5,202	1,420 (e)	(949)	471
3	ISO/PX & Other Wholesale Market Interface Costs															
4	Electric Supply Settlements System	-	1,255	1,255	-	1,753	1,753	-	3,008	3,008	-	3,765	3,765	-	(757)	(757)
5	Utility Energy Supply Forecast (b)	-	272	272	-	471	471	-	743	743	-	743	743	-	-	-
6	Existing Contractual Obligation Scheduling & Settlements	-	83	83	-	150	150	-	233	233	20	198	218	(20)	35	15
7	Power System Control Modifications	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Meter Certification	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Generation Revenue Quality Meters	511	2,227	2,738	226	4,158	4,384	739	6,383	7,122	924	5,943	6,867	(185)	440	255
10	Management of Existing Transmission Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Generation ISO/PX Settlement, Billing, and Bidding Systems	2,119	5	2,124	4,075	35	4,110	6,194	40	6,234	5,537	284	5,821	657	(244)	413
12	Western Power Exchange Project	192	-	192	976	520	1,496	1,168	520	1,688	1,563	375	1,938	(395)	145	(250)
13	Existing Wholesale Contracts - ISO Assessment Charge	696	-	696	2,473	-	2,473	3,169	-	3,169	3,270	-	3,270	(101)	-	(101)
14	Existing Wholesale Contracts - PX Assessment Charge	18	-	18	40	-	40	58	-	58	58	-	58	-	-	-
15	ISO/PX & Other Wholesale Market Interface Costs-CIS	111	72	183	89	28	117	200	100	300	206	-	206	(6)	100	94
16	Hourly-Interval Meter Installation & Reading Costs															
17	Hourly-Interval Meter Reading Costs (Excluding DA DSMA & QF Ch	3,415	8,718	12,133	5,577	14,373	19,950	8,992	23,091	32,083	9,337	17,605	26,942	(345)	5,486 (e	4,141
18	Changes to the QF Payment System	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-
19	ISO/PX Implementation (Uplift) Costs															
20	ISO-Grid Management Charge (d)	3,806	0	3,806	7,612	-	7,612	11,418	-	11,418	12,075	-	12,075	(657)	-	(657)
21	PX Assessment Charge	11,349		11,349	-	-	-	11,349	-	11,349	11,349	-	11,349	-	-	-
22	PX Volumetric Charge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	UDC Billing System Modification Costs (Excluding DA DSMA)	4,279	6,172	10,451	3,389	14,628	18,017	7,668	20,800	28,468	5,564	14,500	20,064	2,104 (e)	6,300 (e	8,404
24	Customer Information Release Systems Costs	84	122	206	676	28	704	760	150	910	1,001	-	1,001	(241)	150	(91)
25	Consumer Education Program	16,938	-	16,938	6,264	-	6,264	23,202	-	23,202	23,202	-	23,202	-	-	-
26	Electric Education Trust	-	-	-	4,536	-	4,536	4,536	-	4,536	4,536	-	4,536	-	-	-
27	Environmental Impact Report	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total IRMA Subaccounts	45,758	19,109	64,867	39,106	38,221	78,327	84,864	58,330	140,194	82,633	44,624	127,257	2,231	10,706	12,937
29	DA Discretionary Services Memorandum Account (DSMA)															
30	DA DSMA for Hourly-Interval Meter Reading Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	DA DSMA for UDC Billing System Modification Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Total DA Discretionary Svcs. Memo. Acct.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	ISO/PX Memorandum Accounts															
34	ISO Memorandum Account	-	-	-	-	-	-	-	-	-	-	-	-			
35	PX Memorandum Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Total ISO/PX Memo Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total	45,758	19,109	64,867	39,106	38,221	78,327	84,864	58,330	140,194	82,633	44,624	127,257	2,231	10,706	12,937

Foot Note	Comments
a	The amounts shown are estimates from Schedule 3B of PG&E's June 18, 1998 Prehearing Conference Statement (PHC).
b	Corrects the 8/5/98 Updated 1998 Costs version to reflect all amounts as capital expenditures instead of expense. See Schedule 3B of PG&E's June 18, 1998 PHC.
c	Cost increase is due to unanticipated increases in direct access scope which included (1) additional work to accommodate the delay in implementing direct access on March 31, 1998, instead of January 1, 1998; and (2) additional work to respond to unanticipated operational issues and ESP problem resolution. Cost increase has no impact on the 1999 GRC estimate. The total project cost could possibly increase in the future, but any increase would not occur until after 1998.
d	The $15.2 million amount is calculated by multiplying the development and start-up portion of the 0.7831 $/MWh GMC rate (i.e., 0.1832 $/MWh) shown in Table 3J, page 3-67 of PG&E's May 1, 1998 Section 376 filing, and PG&E's share of the 1998 annual ISO Volume Forecast (i.e., 83,094,000 MWh). The 0.1832 $/MWh amount is calculated as $35,726,000 (line 13, page 3-25) divided by the total ISO transmission volume of 195,000,000 MWh as shown in Table 3J, line 17, page 3-67 of PG&E's Section 376 filing, and supersedes the 0.1716 $/MWh amount shown on line 14, page 3-25. .
e	At the time estimates were gathered, work was being shifted from planning to operations. Contract labor estimates and consulting contracts costs went up; There was more work than anticipated.

ATTACHMENT 2

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

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BEFORE THE PUBLIC UTILITIES COMMISSION
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SETTLEMENT AGREEMENT

I.

PARTIES

The parties to this Settlement Agreement are the Office of Ratepayer Advocates of the California Public Utilities Commission ("ORA"), the California Manufacturers Association ("CMA"), the California Large Energy Consumers Association ("CLECA"), the Cogeneration

Association of California ("CAC"), the Energy Producers and Users Coalition ("EPUC"), the University of California and California State University ("UC/CSU"), Federal Executive Agencies ("FEA"), and San Diego Gas & Electric Company ("SDG&E") (collectively, "Parties").

II.

RECITALS

A. SCOPE OF THE AGREEMENT

Public Utilities Code Section 376 ("Section 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. On May 1, 1998, SDG&E filed an application ("Application") for authority to recover costs it has expended and will expend for programs to accommodate implementation of direct access, the ISO and PX pursuant to Section 376. This Settlement Agreement resolves or otherwise disposes of all issues in connection with the Application, as well as direct access cost recovery issues identified in SDG&E's Cost of Service Study proceeding, A.98-01-014.

Genuine disputes have existed among the Parties concerning: (1) SDG&E'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 Section 376 and the interpretation thereof, (2) the mechanism for tracking displaced CTCs, (3) the level of cost recovery of SDG&E'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 Commissioners 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.

The Parties also recognize that, pursuant to the Joint Motion for Adoption of Settlement Agreement and associated Settlement Agreement, dated August 28, 1998, regarding SDG&E's 1999 Cost of Service Study, filed as A.98-01-014, for which SDG&E sought cost recovery through 2002, SDG&E and various parties agreed that certain specified costs should be considered in this proceeding for recovery. The Parties agree and resolve that those costs are reflected in the Internally Managed Costs defined in Section III.B of this Settlement Agreement and are recoverable through this Settlement Agreement. Further, the Parties agree that this cost recovery mechanism for Internally Managed Costs shall continue through the later of the end of 2002 or the Commission's resolution of SDG&E's next Cost of Service Study which will be filed no later than December 21, 2001.

B. SDG&E'S PRESENTATION

SDG&E's proposal for identifying and recovering costs subject to Public Utilities Code Section 376 is contained in seven chapters of testimony and accompanying workpapers filed as SDG&E's Application in the instant proceeding. In addition, SDG&E has responded to a large number of data requests. At the behest of Commissioner Bilas and ALJ Minkin, SDG&E initiated settlement discussions with the participants in this proceeding to resolve the issues raised by SDG&E's Application. SDG&E believes that the accompanying settlement reflects the extensive discussions of the signatory parties and presents a fair accommodation of the interests represented.

C. ORA'S PRESENTATION

The Office of Ratepayer Advocates ("ORA") actively participated in this proceeding, reviewed SDG&E's filing in detail, engaged in extensive discovery with regard to Phase I and Phase II issues, and filed testimony addressing a host of Section 376 issues. While ORA was concerned with many specific issues, ORA was particularly concerned with two overall issues. First, ORA was concerned that SDG&E 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 Section 376 eligibility adequately addresses ORA's concerns with the broadness of SDG&E's request. Section 376 eligibility is limited to SDG&E's actual externally managed costs (eligible categories are forecast to be $32.5 million) plus $16.8 million of internally managed costs, for an estimated total of $49.3 million in Section 376 eligible costs. This compares favorably to SDG&E's request for $129.2 million on a revenue requirement basis.

ORA is further satisfied that an authorization of $35.7 million of transition period internally managed costs responds to ORA's concerns about regulatory process and utility management control over cost incurrence. The $35.7 million of internally managed costs represents a $3.5 million reduction from SDG&E's forecasts of such costs. The Settlement Agreement avoids the need for reasonableness review of both costs which have been incurred and costs to be incurred. Based on ORA's review of internally managed costs, the $35.7 million authorization provides the appropriate means and responsibility to SDG&E 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 SDG&E's ability to seek any further costs, while providing SDG&E a fair opportunity to deal with future regulatory mandates which impose substantial costs for new programs upon SDG&E.

D. THE CALIFORNIA MANUFACTURERS ASSOCIATION'S AND THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION'S PRESENTATION

CMA and CLECA sponsored the testimony of Dr. Barkovich in this proceeding. Dr. Barkovich's testimony set forth several principles which she recommended the Commission utilize in evaluating the eligibility of various costs for Section 376 treatment. Overall, she recommended that the Commission maintain the balance between utility and ratepayer interests contemplated in AB 1890. CMA and CLECA believe that the Settlement is consistent with the principles set forth in Dr. Barkovich's testimony and believe that the cap on Section 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.

E. FEDERAL EXECUTIVE AGENCIES' PRESENTATION

The Department of the Navy and Federal Executive Agencies ("FEA") participated actively in this proceeding, reviewed SDG&E's filing in detail, and engaged in extensive discovery with regard to both Phase I and Phase II issues by reviewing SDG&E's responses to FEA's and other parties' data requests. FEA filed the testimony of witness Ralph C. Smith, who addressed Section 376 eligibility issues and the definition of "incremental" costs for Section 376 purposes. Referring to SDG&E's filed direct testimony at page 7, FEA was concerned with the total amount of Section 376 costs claimed by SDG&E totaling $129.2 million on a cash flow basis: $90.7 million listed as externally managed costs and $39.4 million claimed as internally managed costs. FEA was particularly concerned with the $20.9 million PX Volumetric Charge and the $50.7 million ISO Grid Management Charge set forth in SDG&E's filing because these cost categories appeared to be in large part of on-going, post implementation costs that are not eligible for Section 376 treatment.

FEA is satisfied that the settlement removes the $20.9 million PX Volumetric Charge and removes the portion of the ISO Grid Management Charge that relates to costs other than ISO start-up costs. Furthermore, FEA is satisfied that the $16.8 million cap for SDG&E's Section 376 internally managed costs is reasonable and consistent with FEA's recommendations in this proceeding.

F. THE UNIVERSITY OF CALIFORNIA'S AND CALIFORNIA STATE UNIVERSITY'S PRESENTATION

The University of California and California State University believe that the Settlement and its cap on Section 376 costs is consistent with principles set forth in AB 1890 which seek to balance ratepayer and utility interests. UC and CSU therefore support the Settlement as reasonable resolution of how Section 376 restructuring costs should be treated pursuant to AB 1890 and prior Commission decisions.

G. THE PRESENTATION OF THE ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA

EPUC and C.A.C. sponsored the testimony of James A. Ross. Mr. Ross testified that Section 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. 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.

II. SETTLEMENT PROCESS

Shortly after the June 25, 1998 prehearing conference in this case, the Parties began discussions of the similarities and differences in positions each intended to advocate before the California Public Utilities Commission ("Commission"). 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 Management Statement filed jointly on August 24, 1998 by many active parties to this docket. Following the meet and confer session, a consensus among several parties emerged regarding the issues and resolution of SDG&E's Application which is now reflected in this Settlement Agreement.

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 and Electric Education Trust Costs. Upon Commission approval of this Settlement Agreement, EMCs for the enumerated programs will be determined to "have been funded by SDG&E and have been found by the Commission or the Federal Energy Regulatory Commission to be recoverable from the utility's customers" pursuant to Section 376.

B. INTERNALLY MANAGED COSTS ("IMCs"):

IMCs are defined as the following costs described in SDG&E's testimony in this proceeding (which is incorporated by reference): direct access implementation costs (Chapter II), PX load bidding and demand settlement (Chapter III.B.), ISO/PX interfaces (Chapter III.C. and D.), hourly interval meter install and reading costs (Chapter IV), UDC billing systems modification costs (Chapter V), Customer Information Release System costs (Chapter VI), and Environmental Impact Report costs (discussed in Chapter I). IMC cost categories are those identified as categories of IMC costs in the table on page 7 of Chapter I of SDG&E's prepared testimony, and only those cost categories are considered for cost recovery for the years 1997 through 2002; in addition, SDG&E's Environmental Impact Report costs, are deemed Internally Managed Costs. Upon adoption of this Settlement Agreement, IMCs for the enumerated programs will be determined to "have been funded by SDG&E and have been found by the Commission or the FERC to be recoverable from the utility's customers" pursuant to Section 376. As discussed herein, the revenue requirement for IMCs shall be fixed at $35.7 million.

C. SECTION 376 INTERNALLY MANAGED COSTS ("376 IMCs"):

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 $16.8 million and is equivalent to 41.7% of IMCs.

D. 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 SDG&E 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 $1.0 million or greater in annual revenue requirement for programs lasting longer than one year, or $2.0 million or greater in revenue requirements for a single restructuring-related, ISO, or PX program.

E. TRANSITION PERIOD

The "transition period" refers to the electric restructuring transition period from January 1997 through December 31, 2001.

F. 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 SDG&E'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 as follows:

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 SDG&E shall be authorized to recover the full amount of EMCs on a dollar-for-dollar basis. To this end, the Parties agree that SDG&E's level of recoverable EMCs shall be the actual amounts, including payments or credits, or other amounts billed or assigned to SDG&E, whether these actual amounts exceed or are less than the estimated amounts depicted in Table B (attached). The Parties agree that SDG&E shall continue to track its EMCs through the earlier of the date SDG&E is determined to have recovered its CTCs or December 31, 2001. In the event that tracking continues through December 31, 2001, SDG&E shall determine its total EMCs as of December 31, 2001.

The Parties agree that SDG&E shall recover $ 35.7 million of authorized IMCs as reflected in the Revenue Requirements in Table A (attached).

B. COST RECOVERY MECHANISM

The Parties agree that the levels of SDG&E's direct access, ISO and PX expenditures, as specified in Section IV.A above, are recoverable in SDG&E's electric rates according to the cost recovery mechanism set forth in this section. The Parties agree that SDG&E shall file an annual Advice Letter to establish the rate to recover the IMC and EMC revenue requirements specified by Tables A and B (attached). Except for this advice letter filing and the potential filings identified in Section IV.E, 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

SDG&E or any approval of the Commission or any Party other than the Commission's approval of this Settlement Agreement.

The Parties recognize that the costs specified in Section IV.A, above, except those covered by the ISO Grid management charge, are not presently recovered in SDG&E's rates. The Parties also recognize and agree that the costs specified in Section IV.A, above, are not presently pending in and subject to recovery pursuant to the Joint Motion for Adoption of Settlement Agreement and associated Settlement Agreement, dated August 28, 1998 regarding SDG&E's 1999 Cost of Service Study, filed as A.98-01-014 or in any other pending proceeding. The Parties further recognize and agree that the costs recovered pursuant to this Settlement Agreement are not to be included in SDG&E's distribution rate.

Parties agree that SDG&E will establish a Consolidated Restructuring and Section 376 Account to become effective on January 1, 1999 or as soon as authorized by the Commission. The Consolidated Restructuring and Section 376 Account will be subdivided into an Internally Managed Cost Account ("IMCA") and an Externally Managed Cost Balancing Account ("EMCBA"). Separate rate components will be set annually (1) through the end of year 2002 based on the IMCA revenue requirement shown in Table A (attached), and (2) through the end of 2001 based initially on the EMCBA revenue requirement represented in Table B (attached), which reflects a forecast of projected EMCs, which are not recovered elsewhere in FERC or Commission rates. The total of the billed revenues recorded in the Consolidated Restructuring and Section 376 Account will be transferred to SDG&E's Transition Revenue Account ("TRA") in the event the Commission approves SDG&E's proposal to establish a TRA in A.98-07-006.

On a monthly basis, beginning January 1, 1999 or as soon as authorized by the Commission, SDG&E will compare billed revenues from the EMC rate component to actual

EMCs. Any over- or under-collection resulting from this comparison will be reflected in the subsequent year's EMC rate component. Any over- or under-collection resulting from this comparison will receive the three-month commercial rate of interest.

The rate set to recover EMCs for calendar year 1999 or any portion thereof will recover the EMCs forecasted for 1999 as well as recorded costs for 1997 and 1998. The rate set to recover IMCs for calendar year 1999 or any portion thereof will recover the IMC revenue requirements for 1997 through 1999 as shown in Table A (attached). The Parties agree that the methodology for determining revenue fluctuations due to sales will be consistent with the methodology adopted by the Commission in A.98-01-014 regarding SDG&E's Cost of Service Study.

As indicated in Section II of the Settlement Agreement, in connection with the Joint Motion for Adoption of Settlement Agreement and associated Settlement Agreement, dated August 28, 1998, regarding SDG&E's 1999 Cost of Service Study, filed as A.98-01-014, which covers the period 1999 through 2002, SDG&E and various parties agreed that certain specified costs should be considered in this proceeding for recovery. The Parties agree and resolve that those costs are reflected in the IMCs specified in Section IV-A of this Settlement Agreement and are recoverable through this Settlement Agreement.

Further, the Parties agree that this cost recovery mechanism for IMCs shall continue through the later of the end of 2002 or the Commission's resolution of SDG&E's next Cost of Service Study which will be filed no later than December 21, 2001.

C. DERIVATION OF CTC DISPLACEMENT AMOUNT

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

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

The Parties agree that SDG&E shall be authorized to recognize $ 16.8 million in 376 IMCs for the purpose of determining the CTC Displacement Amount at the conclusion of the transition period. This is a fixed amount not subject to adjustment.

D. CTC DISPLACEMENT TRACKING ACCOUNT MECHANISM

SDG&E agrees to enter each month the total amount of EMCs and 376 IMCs in a new "CTC Displacement Tracking Account." SDG&E agrees to compare the total amount entered in the "CTC Displacement Tracking Account" to SDG&E's Transition Cost Balancing Account ("TCBA") balance to evaluate SDG&E'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 SDG&E shall be entitled to recover the CTC Displacement Amount 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 SDG&E shall recover the amount in the CTC Displacement Tracking Account.

E. 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 SDG&E's ability to recover restructuring costs, the Parties hereby provide for a limited exception for such major events. Therefore, the Parties agree that SDG&E shall have the opportunity to seek recovery of substantial future regulatorily required restructuring costs as specified below.

If SDG&E determines a substantial event has occurred, or if the FERC or the Commission is considering issues which could lead to a substantial event, SDG&E agrees to promptly meet and confer with the other signatory Parties. The Parties shall discuss issues raised by the event SDG&E determines is substantial and shall make good faith efforts to resolve such issues. If all Parties agree, SDG&E may seek recovery of the cost associated with the new regulation by advice letter. However, the Parties need not agree on the identification or resolution of any issues, and SDG&E may seek recovery of such costs by an application. Parties may take such positions as they see fit with respect to Commission or FERC consideration of the substantial event. SDG&E's filing to the Commission shall cite ordering paragraphs of the FERC or Commission decision which supports SDG&E'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 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 SDG&E 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.

F. FURTHER REVIEWS AND ADJUSTMENTS

The Parties agree that EMCs are not subject to further reasonableness reviews. The Parties further agree that SDG&E shall track its IMCs during the transition period until such time as the ORA indicates to SDG&E, that in ORA's sole discretion, such tracking is not necessary. SDG&E will make reasonable efforts to provide such information in a format acceptable to ORA. 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 CONDITION

A. TERM OF SETTLEMENT AGREEMENT

The Parties agree that for purposes of determining the CTC Displacement Amount, this Settlement Agreement shall be in effect until such costs are determined as of December 31, 2001. For purposes of cost recovery of IMCs, this Settlement Agreement shall be in effect through the end of 2002 or the Commission's resolution of SDG&E's next Cost of Service Study which will be filed no later than December 31, 2001, whichever is later.

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. The Parties acknowledge the value of including all active participants in this case and settlement process. In particular, the Parties acknowledge the contribution of the Office of Ratepayer Advocates of the California Public Utilities Commission ("ORA"), the California Manufacturers Association ("CMA"), the California Large Energy Consumers Association ("CLECA"), the Cogeneration Association of California ("CAC"), the Energy Producers and Users Coalition ("EPUC"), the University of California and California State University ("UC/CSU"), Federal Executive Agencies ("FEA"), and San Diego Gas & Electric Company ("SDG&E") through their detailed reports, as well as the participation of all intervenors in the discovery and settlement negotiation phases of this proceeding. Each presented extensive substantiation of its positions during the negotiations and participated in an informed, expert manner.

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 in the prepared testimony of SDG&E, the Office of Ratepayer Advocates of the California Public Utilities Commission ("ORA"), the California Manufacturers Association ("CMA"), the California Large Energy Consumers Association ("CLECA"), the Cogeneration Association of California ("CAC"), the Energy Producers and Users Coalition ("EPUC"), the University of California and California State University ("UC/CSU"), Federal Executive Agencies ("FEA"), and San Diego Gas & Electric Company ("SDG&E"), as well as numerous proposals offered by each of these and other 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.

L. APPENDICES

Tables A and B to this Settlement Agreement as listed below are part of the agreement of the Parties and are incorporated into this Settlement Agreement by reference.

Table A	Internally Managed Costs Revenue Requirement
Table B	Externally Managed Costs Revenue Requirement

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.

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November 12, 1998

TABLE A

Internally Managed Costs
Revenue Requirement
($ in millions)

1997	$	521
1998		7,571
1999		8,088
2000		9,414
2001		10,075
TOTAL (1997-2001)	$	35,669
2002	$	10,075

TABLE B

Externally Managed Costs
Revenue Requirement
($ in millions)

1997	$	2,438
1998		12,697
1999		5,797
2000		5,797
2001		5,797
TOTAL (1997-2001)	$	32,524

(END OF ATTACHMENT 2)